PG&E Corp
Form 10-K
February 18, 2016

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, 2015

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

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

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

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

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation	Yes	No
Pacific Gas and Electric Company	Yes	No

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

PG&E Corporation
Pacific Gas and Electric Company

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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, 2015, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$23,628 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 12, 2016:

PG&E Corporation:	492,830,471 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 2016 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.

2015 Form 10-K	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015
AB	Assembly Bill
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
ARO	asset retirement obligation
ASU	accounting standard update
CAISO	California Independent System Operator
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
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	Department of Energy
EPA	Environmental Protection Agency
EPS	earnings per common share
EV	electric vehicle
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
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
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
ORA	Office of Ratepayer Advocates
PSEP	pipeline safety enhancement plan
QF	Qualifying facility
Regional Board	California Regional Water Quality Control Board, Lahontan Region
REITS	Global real estate investment trust
ROE	return on equity
RPS	renewable portfolio standard

SB	senate bill
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
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, 2015, PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 20 of which were employees of the PG&E Corporation. Of the Utility's regular employees, approximately 13,500 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"). The SEIU collective bargaining agreement will expire on July 31, 2016. The two agreements with IBEW will expire on December 31, 2016. The agreement with ESC, originally scheduled to expire on December 31, 2015, automatically renewed for a period of one year pending the negotiation of a new agreement with the union. In January 2016, the Utility and ESC reached a tentative new agreement, subject to ratification by members of ESC. If ratified, the new agreement with ESC will be retroactive to January 1, 2016 and 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. The information contained on these websites is not part of this or any other report that PG&E Corporation and the Utility files with, or furnishes to, the SEC.

In April 2015, the CPUC issued decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the pipeline accident that occurred in San Bruno, California on September 9, 2010 (the "San Bruno accident"). A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") to impose penalties on the Utility totaling $1.6 billion. For more information about the Penalty Decision see Item 1.A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below. The Utility also faces criminal charges in the U.S. District Court for the Northern District of California alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act and that the Utility obstructed the NTSB's investigation into the cause of the San Bruno accident. The trial currently is scheduled to begin on March 22, 2016. For more information about the criminal proceeding, see "Enforcement and Litigation Matters" in MD&A, Item 1.A. Risk Factors, and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below.

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 "Cautionary Language Regarding 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 consists of five members 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 electricity and natural gas distribution operations, electricity 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.

As discussed above, in April 2015, the CPUC concluded its three investigative enforcement actions against the Utility by imposing penalties totaling $1.6 billion. (For more information about the Penalty Decision, see Item 1.A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below.) The CPUC is also conducting investigative enforcement proceedings relating to the Utility's natural gas distribution facilities record-keeping practices and the Utility's potential violations of the CPUC's ex parte communication rules. (See "Enforcement and Litigation Matters" in MD&A for more information.) Further, in August 2015, the CPUC began an investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. (For more information, see "Regulatory Matters" in MD&A.)

The CPUC has adopted separate gas and electric safety enforcement programs that authorize the SED to issue citations and impose fines for violations of certain regulations. Under both the gas and electric programs, the SED is required to impose the maximum statutory penalty of $50,000 for each separate violation and has the discretion to impose daily fines for continuing violations. During 2016, the CPUC is expected to develop and implement improvements and refinements to the electric and gas safety citation programs, including steps to reconcile the differences between the two 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 development of energy storage technologies and facilities, 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 electricity 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 systems 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 electricity 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 violation 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 electricity 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 generation 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” in MD&A and Item 1.A Risk Factors below.)

Other Regulation

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.

The CARB is the state agency charged with setting and monitoring GHG and other emission limits. The CARB also is 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 it 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 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 gas and electric rates vary depending on seasons mostly due to the influence of weather. Gas service rates generally increase during the winter months (October through March) to account for the gas peak due to heating while electricity rates increase during summer (June – September) because of higher summer costs, driven by air conditioning loads.

During 2015, 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 and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. (See "Legislative and Regulatory Initiatives" in MD&A for additional 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 "Results of Operations" in MD&A.) These mechanisms can also create financial risk. For a discussion of the re-opened proceeding to review incentive revenues awarded for the 2006-2008 energy efficiency cycle, see "Rehearing of CPUC Decisions Approving Energy Efficiency Incentive Awards" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. below.

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 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 (known as "attrition rate adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition 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 residential and other customer 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. In its 2015 GT&S rate case, the Utility has requested that the CPUC approve a total annual revenue requirement of $1.263 billion for the Utility’s anticipated costs of providing natural gas transmission and storage services for 2015. The Utility also requested revenue increases of $83 million in 2016 and $142 million in 2017. See “Regulatory Matters – 2015 Gas Transmission and Storage Rate Case” in MD&A for additional information.

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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 at 10.40%. The CPUC also 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. During 2015, the adjustment mechanism was not triggered so the Utility’s authorized ROE will remain at 10.40% for 2016. On February 12, 2016, a proposed decision was issued, that, if approved by the CPUC, will preclude the Utility from using the mechanism before its next cost of capital application. As a result, if the proposed decision is approved, the Utility’s capital structure and ROE will not be adjusted for 2017. The CPUC will review the Utility’s capital structure and ROE for 2018 in the Utility’s next cost of capital proceeding. The Utility is required to file its 2018 cost of capital application by April 20, 2017.

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. (See “Regulatory Matters – FERC TO 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 electricity 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 electricity procured from third parties or 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 procurement plans based on long-term demand forecasts. The CPUC has approved the Utility's procurement plan covering 2012 through 2024.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved electricity 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.

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 additional 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 and Transportation Costs

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

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs. 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 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 Alberta Utilities Commission and the National Energy Board. 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.

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.

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As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. The CPUC also is considering the Utility's request for approval of the phased deployment of an electric vehicle charging infrastructure in response to the CPUC's December 2014 decision adopting a policy to expand the California utilities' role in developing an EV charging infrastructure to support California's climate goals. (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 2015 represented by each major electricity resource, and further discussed below.

Total 2015 Actual Electricity Generated and Procured – 72,113 GWh (1):

	Percent of Bundled Retail Sales	
Owned Generation Facilities		
Nuclear	22.6%	
Small Hydroelectric	0.7 %	
Large Hydroelectric	4.6 %	
Fossil fuel-fired	8.9 %	
Solar	0.4 %	
Total		37.2%
Qualifying Facilities		
Renewable	3.0 %	
Non-Renewable	6.5 %	

Total		9.5 %
Irrigation Districts and Water Agencies		
Small Hydroelectric	0.1 %	
Large Hydroelectric	0.6 %	
Total		0.7 %
Other Third-Party Purchase Agreements		
Renewable	25.3 %	
Large Hydroelectric	0.7 %	
Non-Renewable	9.4 %	
Total		35.4 %
Others, Net (2)		17.2 %
Total (3)		100 %

(1) This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.

(2) Mainly comprised of net CAISO open market purchases.

(3) Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by transmission and distribution related system losses.

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Renewable Energy Resources. California law established a "renewable portfolio standard" (referred to as "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 which, effective January 1, 2016, 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 compliance period thereafter. SB 350 establishes increasing interim renewable energy targets for the periods between 2020 and 2030 but also 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 has stated its intent to propose a decision in late 2016 implementing SB 350's provisions requiring higher RPS targets and other changes made by the statute to the RPS rules.

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 2015, 29.5% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 25% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (3.0%), the Utility's small hydroelectric facilities (0.7%), and the Utility's solar facilities (0.4%).

The total 2015 renewable deliveries shown above were comprised of the following:

Type	GWh	Percent of Bundled Retail Sales
Biopower	3,141	4.4%
Geothermal	3,664	5.0%
Wind	5,451	7.6%
Solar	8,157	11.3%
RPS-Eligible Hydroelectric	878	1.2%
Total	21,291	29.5%

Energy Storage. As required by California law, the CPUC has established initial energy storage procurement targets to be achieved by each load-serving entity, such as the Utility. The Utility must hold Requests for Offers (RFOs) to meet biennial targets and procure 580 MW of energy storage which must be operational by the end of 2024. The Utility's 2014-2015 energy storage procurement target was 80.5 MW. The Utility initiated its RFO on December 1, 2014 to obtain at least 74 MW of transmission and distribution connected energy storage, signed contracts for 75 MW, and submitted those contracts for CPUC approval on the CPUC's December 1, 2015 deadline. The Utility met its remaining 6.5 MW customer-connected target by funding energy storage under the CPUC-mandated Self Generation Incentive Program. On January 1, 2016, the Utility reported its compliance with its 2014-2015 obligations to the CPUC. The Utility must file its 2016-2017 plan for procuring 120 MW of energy storage, consisting of 105 MW of transmission and distribution energy storage and 15 MW of customer-connected storage, by March 1, 2016. A CPUC decision on the Utility's plan is expected before the December 1, 2016 deadline for the Utility to issue its second energy storage RFO. The Utility continues to participate in the CPUC proceeding to refine California's energy storage program, which is considering potentially higher targets and expanded energy storage use cases.

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Owned Generation Facilities. At December 31, 2015, 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 larger operational photovoltaic facilities include the Five Points solar station (15 MW), the Westside solar station (15 MW), the Stroud solar station (20 MW), the Huron solar station (20 MW), the Cantua solar station (20 MW), the Giffen solar station (10 MW), the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). All of these facilities are located in Fresno County, except for the 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, 2015, 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 91 electric transmission substations with a capacity of approximately 63,400 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 Fresno, Madera and Kings counties area. The 70-mile line will connect the Utility-owned and -operated Gates and Gregg substations. The new line will help reduce the number and duration of power outages, improve voltage in the area, support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line is expected to commence operations by 2022, and could come online earlier.

Throughout 2015, 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 accommodate system load growth, secure access to renewable generation resources, 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), 58 transmission switching substations, and 603 distribution substations, with a capacity of approximately 31,400 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 2015 the Utility commenced operations in a new electric distribution control center facility in Rocklin, California, and expects to complete an additional facility in Concord, California, in 2016. These control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2015, 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 83 circuits were outfitted with this equipment, bringing the total deployment to 700 of the Utility’s 3200 distribution circuits. The Utility also installed or replaced 20 distribution substation transformer banks to improve reliability and provide capacity to accommodate growing demand. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2016.

Electricity Operating Statistics

The following table shows certain of the Utility’s operating statistics from 2013 to 2015 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 2015, 2014 and 2013.

	2015	2014	2013
Customers (average for the year)	5,311,178	5,276,025	5,243,216
Deliveries (in GWh) (1)	85,860	86,303	86,513
Revenues (in millions):			
Residential	$5,032	$4,784	$5,091
Commercial	5,278	5,141	4,905

Industrial	1,555	1,543	1,388
Agricultural	1,233	1,172	1,021
Public street and highway lighting	83	79	75
Other (2)	(84)	(172)	(128)
Subtotal	13,097	12,547	12,352
Regulatory balancing accounts (3)	560	1,109	137
Total operating revenues	$13,657	$13,656	$12,489
Selected Statistics:			
Average annual residential usage (kWh)	6,294	6,458	6,752
Average billed revenues per kWh:			
Residential	$0.1719	$0.1603	$0.1643
Commercial	0.1640	0.1585	0.1499
Industrial	0.0973	0.0998	0.0928
Agricultural	0.1610	0.1516	0.1454
Net plant investment per customer	$6,660	$6,339	$6,002

(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.

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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 91% of core customers, representing nearly 80% 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 also is supplied by natural gas 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 2015, the Utility purchased approximately 307,100 MMcf of natural gas (net of the sale of excess supply of gas). Substantially all this natural gas was purchased under contracts with a term of one year or less. The Utility’s largest individual supplier represented approximately 17% of the total natural gas volume the Utility purchased during 2015.

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, 2015, 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 this 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, and firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport this natural gas from supply points in the U.S. Southwest 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.

During 2015, the Utility conducted an annual system-wide review of its transmission pipeline class location designations. The Utility also continued work to install 217 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. As of December 31, 2015, the Utility had installed 235 automatic and remote control shut-off valves, and the NTSB closed that recommendation. The final safety recommendation, considered open and acceptable by the NTSB, involves hydrostatic testing nearly 1,000 miles of the Utility's gas transmission system. The Utility has completed the majority of this task and currently plans to complete the task for the remaining approximately 100 of pipelines (involving primarily short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines) during 2018. Also, as part of the Utility's distribution integrity management program, the Utility completed approximately 23,500 sewer inspections during 2015 to identify and correct conflicts between gas and waste water facilities.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2013 through 2015 (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 2015, 2014 and 2013.

	2015	2014	2013
Customers (average for the year)	4,415,332	4,394,283	4,378,797
Gas purchased (MMcf)	209,194	202,215	240,414
Average price of natural gas purchased	$2.11	$4.09	$3.29
Bundled gas sales (MMcf):			
Residential	144,885	143,514	181,775
Commercial	43,888	42,080	46,668
Total Bundled Gas Sales	188,773	185,594	228,443
Revenues (in millions):			
Bundled gas sales:			
Residential	$1,816	$1,683	$1,870
Commercial	403	419	395
Other	125	51	44
Bundled gas revenues	2,344	2,153	2,309
Transportation service only revenue	649	662	555
Subtotal	2,993	2,815	2,864
Regulatory balancing accounts	183	617	240
Total operating revenues	$3,176	$3,432	$3,104
Selected Statistics:			
Average annual residential usage (Mcf)	35	34	44
Average billed bundled gas sales revenues per Mcf:			
Residential	$12.53	$11.72	$10.29
Commercial	9.18	9.96	8.47
Net plant investment per customer	$2,573	$2,468	$2,234

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 “community choice aggregator” (or “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 who do not affirmatively elect to continue to receive electricity from a utility.

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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 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, either under a consensual transaction or via eminent domain.

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.

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 primarily 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 carbon dioxide (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 special ratemaking mechanism described in Note 13: Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in Item 8.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements of the federal 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 the EPA, the federal agency responsible for implementing the 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, paying for the harm caused to natural resources, and paying for the costs of required 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 must submit final plans to comply with these regulations by September 2016, but may 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 1990 levels by 2020. 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.

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. During 2016, CARB and the California Legislature are likely to consider proposals to achieve additional GHG reductions beyond the 2020 target established in AB 32. 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 2015, 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. 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 increase 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.

Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. 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 2014 totaled more than 58 million metric tonnes of CO–2 equivalent, nearly two-thirds of which came from customer natural gas use. The following table shows the 2014 GHG emissions data the Utility reported to the CARB under AB 32. PG&E Corporation and the Utility publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

Source	Amount (metric tonnes CO2 equivalent)
Fossil Fuel-Fired Plants (1)	2,407,734
Natural Gas Compressor Stations and Storage Facilities (2)	348,155
Distribution Fugitive Natural Gas Emissions	750,223
Customer Natural Gas Use (3)	41,616,935

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

(2) Includes 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 2014 as compared to the national average for electric utilities:

	Amount (pounds of CO2 per MWh)
U.S. Average (1)	1,137
Pacific Gas and Electric Company (2)	435

(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 36% of the Utility's delivered electricity in 2014. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

	2014	2013
Total NOx Emissions (tons)	141	153
NOx Emissions Rate (pounds/MWh)	0.01	0.01
Total SO2 Emissions (tons)	14	17
SO2 Emissions Rate (pounds/MWh)	0.0010	0.0011

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.

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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%. 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 and the board is not expected to issue a final decision regarding Diablo Canyon's compliance with the state policy before January 2017. 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. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

The final requirements of the federal and state cooling water policies could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (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 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. In 2015, the Utility was awarded an additional $21 million for costs incurred between June 1, 2013 and May 31, 2014. The claim for the period June 1, 2014 through May 31, 2015 is 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 and such costs 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 future financial results may be materially affected by the outcome of the federal criminal prosecution of the Utility.

As discussed in MD&A, the Utility is facing federal criminal charges alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act and alleging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident that occurred on September 9, 2010. The maximum statutory fine for each felony count is $500,000, for potential total fines of $6.5 million. The federal prosecutor also seeks to impose an alternative fine which could total approximately $562 million, based on allegations that the Utility derived gross gains of approximately $281 million. The trial currently is scheduled to begin on March 22, 2016.

PG&E Corporation and the Utility have not recorded any charges for potential criminal fines in their consolidated financial statements at December 31, 2015. If the Utility is convicted and a fine is imposed, PG&E Corporation and the Utility will record charges when required in accordance with GAAP. The Utility also could incur material costs, not recoverable through rates, to implement remedial measures that may be imposed by the court, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor. The Utility could also be suspended or debarred from entering into federal procurement and non-procurement contracts and programs.

If the Utility incurred material fines or costs following a conviction, PG&E Corporation may need to issue common stock to raise funds to contribute to the Utility to maintain the required equity component of the Utility's authorized capital structure as the Utility incur charges and costs. These issuances would be incremental to PG&E Corporation's current forecast of common stock issuances and could materially dilute PG&E Corporation's EPS. The trial and any negative publicity associated with it, as well as the Utility's conviction and the imposition of a material fine, if incurred, also could affect the Utility's and PG&E Corporation's credit ratings or outlooks and make it more difficult for PG&E Corporation and the Utility to access the capital markets.

The trial and the Utility's conviction 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 challenge the Utility's request to recover costs that the parties allege are somehow related to the criminal charges.

In addition, the Utility's conviction could result in increased regulatory or legislative pressure to require the separation of the Utility's electric and natural gas businesses, restructure the corporate relationship between PG&E Corporation and the Utility, or undergo some other fundamental corporate restructuring. As discussed under the heading "Regulatory Matters" in MD&A, the SED will evaluate PG&E Corporation's and the Utility's organizational structure in the CPUC's pending investigation to examine the Utility's safety culture.

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. 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 the CPUC's investigations of the Utility's compliance with natural gas distribution record-keeping practices and the Utility's compliance with the CPUC's rules regarding ex parte communications. In addition, there are several other investigations by federal and state law enforcement authorities. The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. Federal and state law enforcement authorities also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. If these investigations 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 SED also could impose material fines on the Utility based on the Utility's self-reports submitted in accordance with the SED's safety citation program and the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way. 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 the next phase will 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; and federal electric reliability standards. The SED could impose fines 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 extent to which its natural gas transmission costs exceed authorized revenues as the Utility complies with the Penalty Decision and incurs other natural gas transmission costs that are unrecoverable or that the Utility has not sought to recover.

The Utility's ability to recover its natural gas transmission and storage costs and earn its authorized ROE could be materially affected by the amount of revenues the CPUC ultimately authorizes the Utility to collect in the 2015 GT&S rate case proceeding and future GT&S rate cases. (See "Regulatory Matters" in Item 7. MD&A.) The Utility continues to incur material unrecoverable costs to meet the Penalty Decision's requirement to fund safety-related projects and programs to be identified by the CPUC in the 2015 GT&S rate case. Depending on how the CPUC designates pipeline safety-related projects and programs the Utility is required to fund, and how the Utility's associated costs are counted toward meeting the $850 million maximum disallowance imposed by the Penalty Decision, the ultimate amount of unrecoverable pipeline-related costs the Utility incurs may be higher than current forecasts. In addition, the Penalty Decision requires the Utility to implement various remedial measures which the CPUC estimated would cost $50 million. Actual costs to implement the remedies could be higher.

In addition, the Utility plans to incur unrecoverable costs to continue performing certain work to complete projects under the PSEP and to identify and remove encroachments from gas transmission pipeline rights-of-way. Actual costs to perform this work could exceed forecasts.

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 the 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 if the Utility is convicted of the federal criminal charges discussed above), 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, 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, 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 the 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 decreased new customer growth 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 primarily residential 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 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 are expected to become effective for new NEM customers of the Utility later in 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 rates 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, and incur costs to meet the Penalty Decision's requirement to incur costs of up to $850 million for safety-related projects and programs to be identified by the CPUC in the 2015 GT&S rate case. 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 outcomes of the on-going criminal prosecution, 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 investors’ confidence in management’s ability to execute its business strategy and restore a constructive regulatory environment. As a result, investors may be less willing to buy shares of PG&E Corporation common stock resulting in a lower stock price. Further, the market price of PG&E Corporation common stock could decline materially after the outcomes are determined. 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 due to a conviction in the on-going criminal prosecution, the pending CPUC investigations, or other enforcement matters, it would require 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.

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;

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- 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 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 a wildfire (known as the "Butte fire") that ignited and spread in Amador and Calaveras counties in Northern California in September 2015 depending on the outcome of the investigations into the cause of the fire. If insurance recoveries are unavailable or insufficient to cover such costs, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected. The Utility also could incur material fines, penalties or disallowances, as a result of enforcement actions taken by the CPUC or other law enforcement agencies.

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.

The Utility's operational and information technology systems could fail to function properly or be damaged by third parties (including cyber-attacks and acts of terrorism), 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. The Utility's business is highly dependent on its ability to process and monitor, on a daily basis, a very large number of tasks and transactions. Despite implementation of security measures, all of the Utility's technology systems are vulnerable to disability or failures due to hacking, viruses, acts of war or terrorism and other causes. The failure of the Utility's operational and information technology systems and networks could significantly disrupt operations; cause harm to the public or employees; result in outages or reduced generating output; damage the Utility's assets or operations or those of third parties; and subject the Utility to claims by customers or third parties, any of which could have a material effect on PG&E Corporation's and the Utility's financial results.

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 maintain, modify, and update its systems and these third-party vendors could cease to exist. Any disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification or implementation of new systems, could result in increased costs, the inability to track or collect revenues, the diversion of management's and employees' attention and resources, and could negatively affect the Utility's ability to maintain effective financial controls, and/or the Utility's ability to 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. The theft, damage, or improper disclosure of confidential information can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, reduce the value of proprietary information, and harm the Utility's reputation.

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.)

In addition, 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.

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, 2015, the Utility's unrecovered investment in Diablo Canyon was $2.3 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. Even if the Utility is not required to install cooling towers, it could incur significant costs to comply with alternative compliances measures or to make payments to support various environmental mitigation projects.

Further, the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon expire in 2018 and 2019. The Utility has requested that the California State Lands Commission renew the leases until 2024 and 2025 when the NRC licenses expire. The California State Lands Commission has deferred acting on the application until later in 2016. It is uncertain what level of environmental review, if any, will be required before the leases can be extended. If the leases are not extended or if the Utility determines that it cannot comply with any new environmental conditions in a feasible and economic manner, then operations at Diablo Canyon would cease and the Utility could incur a material charge for the remaining amount of its unrecovered investment.

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. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 for more information.)

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.

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. Increasing temperatures and changing levels of precipitation in the Utility’s service territory would reduce snowpack in the Sierra Mountains. If the levels of snowpack were reduced, the Utility’s hydroelectric generation would decrease and the Utility would need to acquire additional generation from other sources at a greater cost. 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

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.

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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 11.1 million square feet of real property, including 8.9 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 168,000 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 approved final decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, 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. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine. At December 31, 2015, the Consolidated Balance Sheets include $400 million in current liabilities – other for the one-time bill credit that will be provided to the Utility's natural gas customers in 2016. On January 14, 2016, the CPUC issued final decisions to close these investigative proceedings.

The Penalty Decision requires that at least $689 million of the $850 million disallowance be allocated to capital expenditures, and that the Utility be precluded from including these capital costs in rate base. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the 2015 GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent. The CPUC is expected to issue a final decision in the Utility's 2015 GT&S rate case in 2016 to identify safety-related projects and programs that will be subject to the disallowance. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as counting toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. As a result, the total shareholder-funded obligation could exceed $850 million. For more information, see "Enforcement and Litigation Matters" in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8.

Federal Criminal Indictment

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that superseded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The maximum statutory fine for each felony count is $500,000 for total potential fines of $6.5 million. On December 8, 2015, the court also issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. (The Alternative Fines Act states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss.") The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of the gross gain prior to deciding whether to dismiss those allegations. (Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million.) After considering the additional information submitted by the government, on February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges. The trial on the criminal charges currently is scheduled to begin March 22, 2016.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Consolidated Financial Statements as such amounts are not considered to be probable.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of December 31, 2015, there were six 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. On August 28, 2015, the Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the San Bruno Fire Derivative Cases, based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to co-petitions for writ of mandate previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015, the California Court of Appeal issued an order staying the San Bruno Fire Derivative Cases pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional petition for writ of mandate asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling declining to review the August 28 decision. On December 8, 2015, the Court of Appeal issued a writ of mandate to the Superior Court, ordering the Superior Court to stay all proceedings in the San Bruno Fire Derivative Cases "pending conclusion of the federal criminal proceedings" against the Utility. The other two derivative actions are entitled Tellardin v. PG&E Corp. et. al., pending in the Superior Court of California, San Mateo County, and Iron Workers Mid-South Pension Fund v. Johns, et. al., pending in the United States District Court for the Northern District of California. PG&E Corporation, and the other defendants have not answered or otherwise responded to the complaints in these actions. In the Tellardin action, the defendants must answer or respond to the complaint 30 days after the stay in the San Bruno Fire Derivative Cases is lifted. In the Iron Workers action, the court has not established a deadline by which the defendants must answer or respond. Case management conferences have been scheduled in both actions (March 21, 2016 in the Tellardin action and June 3, 2016 in the Iron Workers action), after which PG&E Corporation will have more information about any further proceedings in these actions.

Investigation of the Butte Fire

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. The California Department of Forestry and Fire Protection ("Cal Fire") is investigating the source of the Butte Fire to determine whether a tree contacted a power line operated by the Utility and was the cause of the fire. Cal Fire has reported that as a result of the fire there were two deaths and 965 structures, including 571 houses, were damaged or destroyed. Cal Fire's investigation is expected to conclude in 2016.

Approximately 27 complaints have been filed against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving more than 600 individual plaintiffs and their insurance companies. Plaintiffs and the Utility filed petitions with the California Judicial Council to coordinate these cases. The petitions were assigned to the Calaveras Superior Court for a recommendation to the Judicial Council. On January 21, 2016, the Calaveras Superior Court issued an order recommending to the Judicial Council that the cases be coordinated in the Superior Court of California, Sacramento County, for all purposes including trial. Among other factors, the Court found that coordination requires a court with a significant number of judges and complex litigation support personnel, neither of which are present in Calaveras County. For additional information, see "Enforcement and Litigation Matters" in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8.

Other Enforcement Matters

The Utility also could be required to pay fines, or incur other unrecoverable costs, associated with the CPUC’s pending investigations of the Utility’s natural gas distribution facilities record-keeping practices and the Utility’s potential violations of the CPUC’s ex parte communication rules. In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility’s self-reports of noncompliance with natural gas safety regulations, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See “Enforcement and Litigation Matters” in Note 13: Contingencies and Commitments of the Notes to the Consolidated Financial Statements in Item 8.

Diablo Canyon 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.

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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 is that the Central Coast Board renew Diablo Canyon's permit.

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, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately $30 million. The Utility would seek to recover these costs through rates charged to customers.

The final requirements of the federal and state cooling water policies (discussed above in Item 1. Business under “Environmental Regulation – Water Quality”) could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. 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 is released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility’s transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County District Attorney notified the Utility in December 2014 that it was contemplating bringing legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. The Utility has been in settlement discussions with the district attorney’s office since that time. On October 28, 2015, the district attorney informed the Utility that it would seek civil penalties in excess of $100,000 but is willing to continue to explore settlement options with the Utility.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANTS

The following individuals serve as executive officers (1) of PG&E Corporation and/or the Utility, as of February 18, 2016. 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.	66	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	57	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
		Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid	August 2007 to March 31, 2011
Geisha J. Williams	54	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
		Senior Vice President, Energy Delivery	December 1, 2007 to May 31, 2011
Jason P. Wells	38	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
		Senior Director and Assistant Controller	November 1, 2008 to September 30, 2011
Dinyar B. Mistry	54	Vice President, Chief Financial Officer, and Controller	October 1, 2011 to present
		Vice President and Controller, PG&E Corporation	March 8, 2010 to present
		Vice President and Controller	March 8, 2010 to September 30, 2011
John R. Simon	51		August 17, 2015 to present

		Executive Vice President, Corporate Services and Human Resources, PG&E Corporation	
		Senior Vice President, Human Resources	April 16, 2007 to August 16, 2015
		Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to August 16, 2015
Karen A. Austin	54	Senior Vice President and Chief Information Officer	June 1, 2011 to present
		President, Consumer Electronics, Sears Holdings	February 2009 to May 2011
Desmond A. Bell	53	Senior Vice President, Safety and Shared Services	January 1, 2012 to present
		Senior Vice President, Shared Services and Chief Procurement Officer	October 1, 2008 to December 31, 2011

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Helen A. Burt	59	Senior Vice President, External Affairs and Public Policy, PG&E Corporation	September 30, 2015 to present
		Senior Vice President, Corporate Affairs	September 18, 2014 to September 30, 2015
		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	48	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	54	Senior Vice President, Power Generation and Chief Nuclear Officer	September 8, 2015 to present
		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
Kent M. Harvey	57	Senior Vice President, Finance, PG&E Corporation	January 1, 2016 to present
		Senior Vice President and Chief Financial Officer, PG&E Corporation	August 1, 2009 to December 31, 2015
		Senior Vice President, Financial Services	August 1, 2009 to August 17, 2015
Julie M. Kane	57	Senior Vice President and Chief Ethics and Compliance Officer	May 18, 2015 to present
		Vice President, General Counsel and Compliance Officer, North America and Corporate Functions, 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, 2013
Gregory K. Kiraly	51	Senior Vice President, Electric Transmission and Distribution	September 8, 2015 to present
		Senior Vice President, Electric Distribution Operations	September 18, 2012 to September 8, 2015
		Vice President, Electric Distribution Operations	October 1, 2011 to September 17, 2012
		Vice President, SmartMeter Operations	August 23, 2010 to September 30, 2011
	43	Senior Vice President, Regulatory Affairs	

Steven E. Malnight		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

Hyun Park	54	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
Jesus Soto, Jr.	48	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	54	Senior Vice President, Energy Policy and Procurement	September 8, 2015 to present
		Senior Vice President, Energy Procurement	October 1, 2008 to September 8, 2015

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

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

As of February 12, 2016, there were 59,317 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange. The high and low sales 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 Utility 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 $100 million during the quarter ended December 31, 2015. PG&E Corporation did not make any sales of unregistered equity securities during 2015 in reliance on an exemption from registration under the Securities Act of 1933, as amended. However, PG&E Corporation recently discovered, based on a review of new accounts opened under its Dividend Reinvestment and Stock Purchase Plan ("DRSPP") since 2013, that it issued and sold shares of common stock under the optional cash purchase feature of its DRSPP more than three years after the related registration statement for the DRSPP became effective, including approximately 19,550 shares for estimated aggregate sales proceeds of $1 million during the year ended December 31, 2015. As a result, participants who purchased these shares may have a rescission right that would allow them to return the shares to PG&E Corporation in exchange for the purchase price paid by such participants, plus interest, less the value of dividends received.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2015, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2015, 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)	2015	2014	2013	2012	2011
PG&E Corporation					
For the Year					
Operating revenues	$ 16,833	$ 17,090	$ 15,598	$ 15,040	$ 14,956
Operating income	1,508	2,450	1,762	1,693	1,942
Net income	888	1,450	828	830	858
Net earnings per common share, basic (1)	1.81	3.07	1.83	1.92	2.10
Net earnings per common share, diluted	1.79	3.06	1.83	1.92	2.10
Dividends declared per common share (2)	1.82	1.82	1.82	1.82	1.82
At Year-End					
Common stock price per share	$ 53.19	$ 53.24	$ 40.28	$ 40.18	$ 41.22
Total assets	63,339	60,127	55,605	52,449	49,750
Long-term debt (excluding current portion)	16,030	15,050	12,717	12,517	11,766
Capital lease obligations (excluding current portion) (3)	49	69	90	113	212
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 16,833	$ 17,088	$ 15,593	$ 15,035	$ 14,951
Operating income	1,511	2,452	1,790	1,695	1,944
Income available for common stock	848	1,419	852	797	831
At Year-End					
Total assets	63,140	59,865	55,049	51,923	49,242
Long-term debt (excluding current portion)	15,680	14,700	12,717	12,167	11,417
Capital lease obligations (excluding current portion) (3)	49	69	90	113	212

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

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

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

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

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

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

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

Summary of Changes in Net Income and Earnings per Share

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS based on earnings from operations) for the year ended December 31, 2015 compared to the year ended December 31, 2014 (see "Results of Operations" below). "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

(in millions, except per share amounts)	Earnings	EPS (diluted)
Income Available for Common Shareholders - 2014	$ 1,436	$ 3.06
Natural gas matters (1)	216	0.45
Environmental-related costs (2)	(4)	(0.01)
Earnings from Operations - 2014 (3)	$ 1,648	$ 3.50
Growth in rate base earnings	105	0.22
Timing of 2015 GT&S cost recovery (4)	(208)	(0.43)
Regulatory and legal matters (5)	(16)	(0.04)
Gain on disposition of SolarCity stock (6)	(13)	(0.03)
Increase in shares outstanding	-	(0.12)
Miscellaneous	3	0.02
Earnings from Operations - 2015 (3)	$ 1,519	$ 3.12
Insurance recoveries (7)	29	0.06
Fines and penalties (8)	(578)	(1.19)
Pipeline-related expenses (9)	(61)	(0.13)
Legal and regulatory related expenses (9)	(35)	(0.07)
Income Available for Common Shareholders - 2015	$ 874	$ 1.79

(1) In 2014, natural gas matters included pipeline-related costs to perform work under the PSEP and other activities associated with safety improvements to the Utility's natural gas system, as well as legal and other costs related to natural gas matters. Natural gas matters also included charges related to fines, third party liability claims, and insurance recoveries in 2014.

(2) In 2014, the Utility reduced its accrual related to the Hinkley whole house water replacement program.

(3) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in notes (1) and (2) above and Notes (7), (8), and (9) below.

(4) Represents expenses during the year ended December 31, 2015 as compared to 2014, with no corresponding increase in revenue. The Utility has requested that the CPUC authorize an increase to the Utility's revenue requirements for 2015, 2016, and 2017 in its 2015 GT&S rate case, and expects a final decision in 2016. Any revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is issued.

(5) Includes legal and other regulatory related costs that were partially offset by incentive revenues.

(6) Represents the larger gain recognized during the year ended December 31, 2014 as compared to 2015.

(7) Represents insurance recoveries of $49 million, pre-tax, for third party claims and associated legal costs related to the San Bruno accident the Utility received during the year ended December 31, 2015. The Utility has received a cumulative total of $515 million through insurance related to $558 million of third-party claims and $92 million of legal costs incurred. No further insurance recoveries related to these claims and costs are expected.

(8) Represents the impact of the Penalty Decision (see Note 13 of the Notes to the Consolidated Financial Statements in Item 8. for before-tax amounts).

(9) In 2015, pipeline-related expenses include costs incurred to identify and remove encroachments from transmission pipeline rights of way and to performremaining work under the Utility's PSEP. Legal and regulatory related expenses include costs incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows

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

- The Outcome of Enforcement and Litigation Matters. Future financial results will be impacted by the unrecoverable pipeline safety-related and remedies costs required by the Penalty Decision. The Utility's future results may also be impacted by various other pending enforcement and regulatory actions, including the federal criminal charges and CPUC investigations of the Utility's compliance with natural gas distribution record-keeping practices and potential violations of the CPUC's ex parte communication rules. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

- The Timing and Outcome of Regulatory Matters. The 2015 GT&S rate case remains pending. The Utility requested that the CPUC authorize a $532 million increase in annual revenue requirements for gas transmission and storage operations beginning on January 1, 2015 with attrition increases in 2016 and 2017. Any revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is reached. (See "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" below for more information.) In September 2015, the Utility filed its 2017 GRC application to request that the CPUC authorize revenue requirements for the Utility's electric generation business and its electric and natural gas distribution business for 2017 through 2019. (See "Regulatory Matters – 2017 General Rate Case" below for more information.) In addition, the Utility has one transmission owner rate case pending at the FERC (See "Regulatory Matters – FERC TO Rate Cases" below.) The outcome of regulatory proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- The Ability of the Utility to Control Operating Costs and Capital Expenditures. Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts authorized in the rate case decisions. In addition to incurring shareholder-funded costs and costs associated with remedial measures required by the Penalty Decision, the Utility also forecasts that in 2016 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. The ultimate amount of unrecovered costs also could be affected by how the CPUC determines which costs are included in determining whether the $850 million shareholder-funded obligation under the Penalty Decision has been met, and the outcome of pending and future investigations and enforcement matters. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's ability to recover costs in the future also could be affected by decreases in customer demand driven by legislative and regulatory initiatives relating to distributed generation resources, renewable energy requirements, and changes in the electric rate structure.

- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. In 2015, PG&E Corporation issued $801 million of common stock with cash proceeds and made equity contributions to the Utility of $705 million. PG&E Corporation forecasts that it will issue a material amount of equity in 2016 and future years to support the Utility's capital expenditures. PG&E Corporation will issue additional equity to fund charges incurred by the Utility to comply with the Penalty Decision, to fund unrecoverable pipeline-related expenses, and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances would have a material dilutive impact on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by the outcome of the matters discussed in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8, Financial Statements and Supplementary Data, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2015 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Cautionary Language Regarding Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

The following discussion presents PG&E Corporation's and the Utility's operating results for 2015, 2014, and 2013. See "Key Factors Affecting Results of Operations, Financial Condition, and Cash Flows" above for further discussion about factors that could affect future results of operations.

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income (loss) available for common shareholders:

(in millions)	2015	2014	2013
Consolidated Total	$874	$1,436	$814
PG&E Corporation	26	17	(38)
Utility	$848	$1,419	$852

PG&E Corporation's net income or loss consists primarily of interest expense on long-term debt, other income or loss from investments, and income taxes. Results include approximately $30 million and $45 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015 and 2014, respectively. PG&E Corporation's operating results in 2013 reflected an impairment loss of $29 million related to tax equity fund investments.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2015, 2014, and 2013. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

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

The Utility's operating results for 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

(in millions)	2015 Revenues and Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	2014 Revenues and Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	2013 Revenues and Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$7,442	$ 6,215	$13,657	$7,059	$ 6,597	$13,656	$6,465	$ 6,024	$12,489
Natural gas operating revenues	2,082	1,094	3,176	2,072	1,360	3,432	1,776	1,328	3,104
Total operating revenues	9,524	7,309	16,833	9,131	7,957	17,088	8,241	7,352	15,593
Cost of electricity	-	5,099	5,099	-	5,615	5,615	-	5,016	5,016
Cost of natural gas	-	663	663	-	954	954	-	968	968
Operating and maintenance	5,402	1,547	6,949	4,247	1,388	5,635	4,374	1,368	5,742
Depreciation, amortization, and decommissioning	2,611	-	2,611	2,432	-	2,432	2,077	-	2,077
Total operating expenses	8,013	7,309	15,322	6,679	7,957	14,636	6,451	7,352	13,803
Operating income	1,511	-	1,511	2,452	-	2,452	1,790	-	1,790
Interest income (1)			8			8			8
Interest expense (1)			(763)			(720)			(690)
Other income, net (1)			87			77			84
Income before income taxes			843			1,817			1,192
Income tax (benefit) provision (1)			(19)			384			326
Net income			862			1,433			866
Preferred stock dividend requirement (1)			14			14			14
Income Available for Common Stock			$848			$1,419			$852

(1) These items impacted earnings.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2015, 2014, and 2013, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues increased $393 million or 4% in 2015 compared to 2014, primarily a result of approximately $490 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case. This increase was partially offset by the absence of approximately $110 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014.

The Utility's electric and natural gas operating revenues that impacted earnings increased $890 million or 11% in 2014 compared to 2013. This amount included an increase to base revenues of $460 million as authorized by the CPUC in the 2014 GRC decision. The GRC decision also resulted in higher base revenues of $150 million in 2014 related primarily to the DOE settlement for spent nuclear fuel storage costs. The total increase in operating revenues included approximately $150 million of PSEP-related revenues, and revenues authorized by the FERC in the TO rate case, as well as revenues authorized by the CPUC for recovery of nuclear decommissioning costs. The Utility also collected higher gas transmission revenues driven by increased demand for gas-fired generation.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased $1.2 billion or 27% in 2015 compared to 2014, primarily due to $907 million in charges associated with the Penalty Decision, consisting of $400 million for the customer bill credit, an additional $100 million charge for the fine payable to the state, and $407 million of disallowed capital charges. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The increase is also due to higher labor and benefit-related expenses of approximately $100 million and fewer insurance recoveries for third-party claims and associated legal costs of $63 million related to the San Bruno accident. No further insurance recoveries related to these claims are expected. These increases were offset by $116 million in disallowed capital recorded in 2014 related to the PSEP.

The Utility's operating and maintenance expenses that impacted earnings decreased $127 million or 3% in 2014 compared to 2013, primarily due to lower third-party claims and associated legal costs of $117 million resulting from the settlement of all outstanding third-party claims, lower disallowed capital expenditures of $80 million and lower insurance recoveries for third-party claims and associated legal costs of $42 million related to the San Bruno accident. These decreases were offset by higher benefit-related expenses and other operating expenses of $120 million in 2014 as compared to 2013.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased $179 million or 7% in 2015 compared to 2014 and $355 million or 17% in 2014 compared to 2013. In 2015, the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the FERC in the TO rate case. In 2014, the increase was primarily due to higher depreciation rates as authorized by the CPUC in the 2014 GRC decision and higher nuclear decommissioning expense reflecting the year-to-date increase as authorized by the CPUC in the nuclear decommissioning triennial proceeding. Additionally, depreciation, amortization, and decommissioning expenses were impacted by an increase in capital additions during 2014 as compared to 2013.

Interest Expense

The Utility's interest expenses increased by $43 million in the year ended December 31, 2015 compared to the same period in 2014, primarily due to the issuance of additional long-term debt. There were no material changes to interest expense in the year ended December 31, 2014 compared to the same period in 2013.

Interest Income and Other Income, Net

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

Income Tax Provision

The Utility's revenue requirements for the 2014 GRC decision period reflects flow-through ratemaking for income tax expense benefits attributable to the accelerated recognition of repair costs and certain other property-related costs for federal tax purposes. PG&E Corporation and the Utility's effective tax rates for 2015 are lower as compared to 2014 and for 2014 as compared to 2013 and are expected to remain lower than the statutory rate in 2016 due to these temporary differences.

The Utility's income tax provision decreased $403 million or 105% in 2015 as compared to 2014. This is primarily the result of the statutory tax effect, $397 million, of the lower income before income taxes in 2015 as compared to 2014. The lower effective tax rate is the result of the tax benefits from property-related timing differences applied to this lower income before income taxes.

The Utility's income tax provision increased $58 million or 18% in 2014 as compared to 2013 primarily due to higher income before income taxes, partially offset by certain reductions in tax expense for flow-through treatment as discussed above.

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

	2015		2014		2013	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	(4.8)		1.6		(2.2)	
Effect of regulatory treatment of fixed asset differences (2)	(33.7)		(14.7)		(3.8)	
Tax credits	(1.3)		(0.7)		(0.4)	
Benefit of loss carryback	(1.5)		(0.8)		(1.0)	
Non-deductible penalties (3)	4.3		0.3		0.7	
Other, net	(0.2)		0.4		(0.9)	
Effective tax rate	(2.2)	%	21.1	%	27.4	%

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

(2) Includes the effect of federal flow-through ratemaking treatment for certain property-related costs in 2015 and 2014 as authorized by the 2014 GRC decision. Amounts are impacted by the level of income before income taxes.

(3) Represents the effects of non-tax deductible fines and penalties associated with the Penalty Decision. For more information about the Penalty Decision see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Utility Revenues and Costs that did not Impact Earnings

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

Cost of Electricity

The Utility's cost of electricity includes the cost of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

(in millions)	2015	2014	2013

Cost of purchased power (1)	$4,805	$5,266	$4,696
Fuel used in own generation facilities	294	349	320
Total cost of electricity	$5,099	$5,615	$5,016
Average cost of purchased power per kWh	$0.100	$0.101	$0.094
Total purchased power (in millions of kWh) (2)	48,175	52,008	49,941

(1) Cost of purchased power was impacted primarily by a decline in the market price of natural gas in 2015 compared to 2014.

(2) The decrease in purchased power resulted from an increase in generation from the Utility's own generation facilities. Gas-fired and nuclear generation increased during the year ended December 31, 2015 as compared to the same periods in 2014.

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

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

(in millions)	2015	2014	2013
Cost of natural gas sold	$518	$813	$807
Transportation cost of natural gas sold	145	141	161
Total cost of natural gas	$663	$954	$968
Average cost per Mcf (1) of natural gas sold (2)	$2.74	$4.37	$3.54
Total natural gas sold (in millions of Mcf)	189	186	228

(1) One thousand cubic feet
(2) Average cost of natural gas sold impacted primarily by a decline in the market price of natural gas in 2015 compared to 2014.

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2015, 2014, and 2013, no material amounts were incurred above authorized amounts.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect related to its financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized long-term capital structure consisting of 52% equity and 48% debt and preferred stock. (See “Ratemaking Mechanisms” in Item 1). The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

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

PG&E Corporation’s and the Utility’s credit ratings may be affected by the ultimate outcome of the pending enforcement and litigation matters. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility’s commodity contracts contain collateral posting provisions tied to the Utility’s credit rating from each of the major credit rating agencies. If the Utility’s credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability positions. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation’s equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue between $600 million and $800 million in common stock during 2016, primarily to fund equity contributions to the Utility. The Utility’s future equity needs will continue to be affected by charges incurred to comply with the Penalty Decision, by unrecoverable pipeline-related expenses, and by fines and penalties that may be imposed in connection with the matters described in “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below. Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation’s EPS.

Cash and Cash Equivalents

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims that were filed in the Utility's reorganization proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility is uncertain when and how the remaining disputed claims will be resolved.

Financial Resources

Debt and Equity Financings

The Utility issued $1.15 billion in long-term debt during the year ended December 31, 2015. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

In February 2015, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million. During 2015, PG&E Corporation sold 1.4 million shares of common stock under this agreement for cash proceeds of $74 million, net of commissions paid of $1 million.

In August 2015, PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offering for cash proceeds of $352 million, net of fees.

In addition, during 2015, PG&E Corporation sold 7.9 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $354 million.

The proceeds from equity issuances were used for general corporate purposes, including the contribution of equity into the Utility. For the year ended December 31, 2015, PG&E Corporation made equity contributions to the Utility of $705 million, of which $300 million was used to pay a fine to the State General Fund as required by the Penalty Decision. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2016.

Revolving Credit Facilities and Commercial Paper Programs

At December 31, 2015, PG&E Corporation and the Utility had $300 million and $1.9 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2015, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 50%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2015, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

PG&E Corporation

For each of the quarters in 2015, 2014, and 2013, the Board of Directors of PG&E Corporation declared common stock dividends of $0.455 per share, for annual dividends of $1.82 per share. Dividends paid to common stockholders by PG&E Corporation were $856 million in 2015, $828 million in 2014, and $782 million in 2013. In December 2015, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $224 million, of which approximately $219 million was paid on January 15, 2016 to shareholders of record on December 31, 2015.

Utility

For each of the quarters in 2015, 2014, and 2013, the Utility's Board of Directors declared common stock dividends in the aggregate amount of $179 million to PG&E Corporation for annual dividends paid of $716 million in each of 2015, 2014, and 2013. In addition, the Utility paid $14 million of dividends on preferred stock in each of 2015, 2014, and 2013. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends. In December 2015, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on February 15, 2016, to shareholders of record on January 29, 2016.

Utility Cash Flows

The Utility's cash flows were as follows:

	Year Ended December 31,		
(in millions)	2015	2014	2013
Net cash provided by operating activities	$3,720	$3,619	$3,416
Net cash used in investing activities	(5,211)	(4,799)	(5,142)
Net cash provided by financing activities	1,495	1,170	1,597
Net change in cash and cash equivalents	$4	$(10)	$(129)

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. During 2015, net cash provided by operating activities increased by $101 million compared to 2014. This increase was primarily due to higher base revenue collections authorized in the 2014 GRC and lower purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above), offset by the payment of a $300 million fine to the State General Fund as required by the Penalty Decision. During 2014, net cash provided by operating activities increased by $203 million compared to 2013. This increase was primarily due to tax refunds received during 2014 compared to tax payments made during 2013 and additional collateral returned to the Utility in 2014 as compared to 2013, offset by higher purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above).

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

- the shareholder-funded bill credit of $400 million to natural gas customers in 2016, as required by the Penalty Decision (see “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement matters (see “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 below);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system (including costs to implement remedial measures and $850 million to pay for designated pipeline safety projects and programs, as required by the Penalty Decision);
- the timing and amount of tax payments (including the bonus depreciation extension), tax refunds, net collateral payments, and interest payments;
- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

Investing Activities

Net cash used in investing activities increased by $412 million during 2015 as compared to 2014 primarily due to an increase of $340 million in capital expenditures and an increase in net purchases of nuclear decommissioning trust investments in 2015 as compared to net proceeds associated with sales of nuclear decommissioning trust investments in 2014. Net cash used in investing activities decreased by $343 million during 2014 as compared to 2013 primarily due a decrease of $374 million in capital expenditures. This decrease was primarily due to lower PSEP-related capital expenditures and the absence of additional investment in the Utility’s photovoltaic program.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur between $5.4 billion and $5.6 billion in 2016.

Financing Activities

During 2015, net cash provided by financing activities increased by $325 million as compared to 2014. During 2014, net cash provided by financing activities decreased by $427 million as compared to 2013. Cash provided by or used in financing activities is driven by the Utility’s financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2015:

	Payment due by period				
(in millions)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Utility					
Long-term debt (1):	$917	$ 2,991	$ 2,888	$ 22,150	$ 28,946
Purchase obligations (2):					
Power purchase agreements:	3,453	6,508	6,035	31,824	47,820
Natural gas supply, transportation, and storage	421	255	208	543	1,427
Nuclear fuel agreements	113	196	231	185	725
Pension and other benefits (3)	388	776	776	388	2,328
Operating leases (2)	40	81	76	195	392
Preferred dividends (4)	14	28	28	-	70
PG&E Corporation					
Long-term debt (1):	8	16	351	-	375
Total Contractual Commitments	$5,354	$ 10,851	$ 10,593	$ 55,285	$ 82,083

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2015 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

(2) See "Purchase Commitments" and "Other Commitments" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

(3) See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.

(4) Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

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

Financial Statements in Item 8.

Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8.

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results.

Department of Interior Inquiry

In September 2015, the Utility was notified that the U.S. Department of Interior ("DOI") had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the allegations contained in the superseding criminal indictment (See Note 13 in the Consolidated Financial Statements in Item 8). The Utility filed its initial response on November 2, 2015, to demonstrate that it is a presently responsible contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. It is uncertain when or if further action will be taken.

Pending Lawsuits and Claims

As of December 31, 2015, there were six 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. On August 28, 2015, the Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the San Bruno Fire Derivative Cases, based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to co-petitions for writ of mandate previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015 the California Court of Appeal issued an order staying the San Bruno Fire Derivative Cases pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional petition for writ of mandate asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling declining to review the August 28 decision. On December 8, 2015, the Court of Appeal issued a writ of mandate to the Superior Court, ordering the Superior Court to stay all proceedings in the San Bruno Fire Derivative Cases "pending conclusion of the federal criminal proceedings" against the Utility. The other two derivative actions are entitled Tellardin v. PG&E Corp. et. al., pending in the Superior Court of California, San Mateo County, and Iron Workers Mid-South Pension Fund v. Johns, et. al., pending in the United States District Court for the Northern District of California. PG&E Corporation, and the other defendants have not answered or otherwise responded to the complaints in these actions. In the Tellardin action, the defendants must answer or respond to the complaint 30 days after the stay in the San Bruno Fire Derivative Cases is lifted. In the Iron Workers action, the court has not established a deadline by which the defendants must answer or respond. Case management conferences have been scheduled in both actions (March 21, 2016 in the Tellardin action and June 3, 2016 in the Iron Workers action), after which PG&E Corporation will have more information about any further proceedings in these actions.

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

REGULATORY MATTERS

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

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2017 General Rate Case

On September 1, 2015, the Utility filed its 2017 GRC application with the CPUC. In the 2017 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or "revenue requirements") that the Utility will be authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility's revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.) In its application, the Utility requested a revenue requirement increase of $457 million, as compared to authorized base revenues for 2016, as shown in the following tables:

Line of Business: (in millions)	Amounts Requested In the GRC Application	Amounts Currently Authorized For 2016	Increase Compared to Currently Authorized Amounts
Electric distribution	$4,376	$ 4,212	$ 164
Gas distribution	1,827	1,742	85
Electric generation	2,170	1,962	208
Total revenue requirements	$8,373	$ 7,916	$ 457
Cost Category: (in millions)			
Operations and maintenance	$1,833	$ 1,664	$ 169
Customer services	367	319	48
Administrative and general	978	1,011	(33)
Less: Revenue credits	(140)	(131)	(9)
Franchise fees, taxes other than income, and other adjustments	185	37	148
Depreciation (including costs of asset removal), return, and income taxes	5,150	5,016	134
Total revenue requirements	$8,373	$ 7,916	$ 457

In its application, the Utility stated that over the 2017-2019 GRC period the Utility plans to make average annual capital investments of approximately $4 billion in electric distribution, natural gas distribution and electric generation infrastructure, and to improve safety, reliability, and customer service. (These annual investments would be incremental to the Utility's capital expenditures for electric and natural gas transmission infrastructure.) The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility's authorized revenues in 2018 and 2019, primarily to reflect increases in rate base due to capital investments in infrastructure and, to a lesser extent, anticipated increases in wages and other expenses. The Utility estimates that this mechanism would result in increases in revenue of $489 million in 2018 and an additional $390 million in 2019.

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In October 2015, the Utility filed supplemental testimony to reduce its original revenue requirement request by approximately $17 million per year based on its forecast that it will incur approximately $61 million for unrecoverable costs to implement the remedies ordered in the Penalty Decision.

On February 22, 2016 the Utility will file an update of its forecasted increase, primarily to reflect the impact of the recent five-year extension of the federal tax code provisions regarding bonus depreciation.

According to the CPUC's current procedural schedule, testimony from the ORA and other parties is due in April 2016, evidentiary hearings are to be held this summer, followed by a proposed decision to be released in November 2016 and a final CPUC decision to be issued in December 2016. The Utility has requested that the CPUC issue an order directing that the authorized revenue requirement changes be effective January 1, 2017, even if the final decision is issued after that date.

2015 Gas Transmission and Storage Rate Case

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

The ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service after January 1, 1956, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of capital expenditures during this period be subject to a reasonableness review and an independent audit. TURN states that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit. On December 18, 2015, the ORA filed a motion in the 2015 GT&S rate case for an Order to Show Cause why the Utility should not be sanctioned $163 million for intentional misrepresentations regarding its compliance with gas safety regulations regarding maximum allowable operating pressure for its gas transmission lines. On December 30, 2015, the Utility filed a response to this motion stating that it does not believe there is merit to the allegations. ORA filed a reply on January 11, 2016, reiterating its allegations.

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

Based on the scoping ruling and procedural schedule that was issued on June 11, 2015, the CPUC plans to issue an initial decision to authorize revenue requirements followed by a second decision to reduce the authorized revenue requirements by the costs of designated safety-related projects and programs up to the $850 million maximum cost disallowance imposed by the Penalty Decision. (See Note 13 in the Consolidated Financial Statements in Item 8 for more information about the CPUC's Penalty Decision.) In accordance with an earlier CPUC decision regarding the Utility's violation of the CPUC's ex parte communication rules made in the GT&S rate case, the first decision could disallow the Utility from recovering up to a five-month portion of the revenue increase that may otherwise have been authorized. It is uncertain how much of the Utility's costs to perform the safety-related projects and programs the CPUC will identify as counting toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. Additionally, the Utility may record additional charges if the CPUC does not authorize capital spending from the prior rate case period. The authorized revenue requirements in the GT&S rate case would be retroactive to January 1, 2015. The ruling states that the case would be completed within 18 months of the date of the ruling, or by December 2016.

FERC TO Rate Cases

On September 30, 2015, the FERC approved a settlement that sets the Utility's 2015 retail electric transmission revenue requirement at $1.201 billion, a $161 million increase over the currently authorized revenue requirement of $1.040 billion.

On July 29, 2015, the Utility requested that the FERC approve a 2016 retail electric transmission revenue requirement of $1.515 billion. The proposed amount reflects a $314 million increase over the settled revenue requirement of $1.201 billion. The Utility forecasts that it will make investments of $1.246 billion in 2016 in various capital projects. The Utility's forecasted rate base for 2016 is $5.85 billion, compared to forecasted rate base of $5.12 billion in 2015. The Utility has requested that the FERC approve a 10.96% return on equity. On September 30, 2015, the FERC accepted the proposed revenue requirement, subject to hearing and refund, and established March 1, 2016 as the effective date for rate changes. Hearings are being held in abeyance pending settlement discussions among the parties.

CPUC Investigation of the Utility's Safety Culture

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned Commissioner will determine the scope of and next actions in the proceeding. The timing scope and potential outcome of the investigation are uncertain.

Diablo Canyon Nuclear Power Plant

The NRC operating licenses for the two nuclear generation units at Diablo Canyon expire in 2024 and 2025. In November 2009, the Utility filed an application with the NRC to seek the renewal of the operating licenses, a process which can take several years. After the March 2011 earthquake in Japan that damaged nuclear facilities, the NRC granted the Utility's request to delay processing its renewal application until certain advanced seismic studies of the fault zones in the region surrounding Diablo Canyon were completed. The seismic studies have been completed and in September 2014, the Utility submitted a report to the NRC and the CPUC's Independent Peer Review Panel ("IPRP") that confirmed the seismic safety of the plant. The IPRP is providing comments on the report and the Utility expects the IPRP to conclude their review and issue a final report in 2016. In addition, the Utility has requested that the California State Lands Commission extend the leases for the land occupied by Diablo Canyon's water intake and discharge structures from the current expiration dates in 2018 and 2019 to 2024 and 2025 when the NRC operating licenses are currently due to expire. The California State Lands Commission has deferred acting on the application until later in 2016. It is uncertain whether the leases will be extended or whether an environmental review will be required before the commission can issue a decision. Finally, the California Water Board is not expected to issue a final decision before January 1, 2017 to address how the Utility's nuclear operations at Diablo Canyon must comply with the state's policy regarding once-through cooling. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024. Based on these and other factors, the Utility is continuing to assess its strategy for license renewal of Diablo Canyon. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1. For a discussion of the Utility's nuclear decommissioning obligations, see Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statements in Item 8.)

LEGISLATIVE AND REGULATORY INITIATIVES

The California Legislature and the CPUC have adopted requirements and policies to accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles, and promote customer energy efficiency and demand response programs. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. CPUC proceedings related to some of these matters are discussed below.

In addition, prompted by a methane gas leak from a natural gas storage facility located in Southern California, the California Legislature has begun to consider adopting new legislation to address natural gas storage operations in California, including increased oversight of natural gas storage facilities and the adoption of new safety and reliability measures. The California Governor also issued an emergency proclamation that requires various state agencies to take immediate action, as discussed below.

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

Natural Gas Storage Facilities

On January 6, 2016 the California Governor ordered the Division of Oil, Gas and Geothermal Resources ("DOGGR") to issue emergency regulations to require gas storage facility operators throughout California, including the Utility, to comply with new safety and reliability measures, including minimum daily inspection of gas storage well heads (using gas leak detection technology such as infrared imaging), ongoing verification of the mechanical integrity of all gas storage wells, ongoing measurement of annular gas pressure or annular gas flow within wells, regular testing of all safety valves used in wells, establishing minimum and maximum pressure limits for each gas storage facility in the state, and establishing a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipes and equipment. The Utility may incur significant costs to comply with the new regulations but anticipates that it would be able to recover such costs through rates.

The DOGGR, the CPUC, the CARB, and the CEC will be required to submit to the California Governor's Office a report that assesses the long-term viability of natural gas storage facilities in California. The report will address operational safety and potential health risks, methane emissions, supply reliability for gas and electricity demand in California, and the role of storage facilities and natural gas infrastructure in the State's long-term GHG emission reduction strategies.

New Renewable Energy Targets

In October 2015, the California Governor signed SB 350 which, effective January 1, 2016, 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 compliance period thereafter. SB 350 includes increasing interim renewable energy targets for the periods between 2020 and 2030 and continues to include 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 targets.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility’s plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility’s proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. The Utility’s 2017 GRC includes a request to recover some of the investment costs that it forecasts it will incur under its proposed electric distribution resources plan.

Electric Rate Reform and Net Energy Metering ("NEM")

On July 3, 2015, the CPUC approved a final decision to authorize the California investor–owned utilities to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision approved increased minimum bill charges for residential customers and also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential electric customers based on time-of-use rates unless customers elect otherwise (known as "default time-of-use rates"). The Utility also may propose to impose a fixed charge on residential electric customers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge in electric rates.

In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected to become effective for new NEM customers of the Utility later in 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 non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay.

Electric Vehicle (EV) Infrastructure Development

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

On September 4, 2015, the assigned CPUC Commissioner and the ALJ issued a scoping memo and procedural schedule that required the Utility to supplement its application by submitting a more phased deployment approach that will be considered in a first phase of the proceeding. On October 12, 2015, the Utility submitted supplemental testimony presenting two separate proposals. In its first proposal, the Utility has requested that the CPUC approve approximately $70 million in capital expenditures to deploy and own 2,510 EV charging stations over approximately 2 years. In its second proposal, the Utility has requested that the CPUC approve approximately $187 million in capital expenditures to deploy and own 7,530 EV charging stations over approximately 3 years. Under the CPUC's schedule, a proposed decision for the first phase of the proceeding is expected to be issued by June 2016. Further deployment of EV charging stations would be considered in a second phase of the proceeding depending on the outcome of the first phase.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of CO2 and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Item 1A. Risk Factors and "Environmental Regulation" in Item 1.)

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment. At December 31, 2015, $140 million and $300 million was accrued in the Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Hinkley site and the Topock site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See "Environmental Remediation Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-speculative purposes (i.e., risk mitigation). The Utility's risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

Commodity Price Risk

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

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs through fixed reservation charges and volumetric charges from long-term contracts, resulting in price and volumetric risk. (See "2015 Gas Transmission and Storage Rate Case" above.)

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $2 million and $1 million at December 31, 2015 and 2014, respectively. During 2015, the Utility's approximate high, low, and average values-at-risk were $2 million, $1 million and $2 million, respectively. During 2014, the value-at-risk amounts were $9 million, $1 million and $5 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2015 and 2014, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be $11 million and $9 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates.)

Energy Procurement Credit Risk

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generation companies, and oil and natural gas production companies located in the United States and

Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

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

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

(in millions)	Gross Credit Exposure Before Credit Collateral (1)	Credit Collateral	Net Credit Exposure (2)	Number of Wholesale Customers or Counterparties >10%	Net Credit Exposure to Wholesale Customers or Counterparties >10%
December 31, 2015	$ 64	$ (11)	$ 53	4	39
December 31, 2014	88	$ (18)	$ 70	3	29

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.

(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

Regulatory Accounting

As a regulated entity, the Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. These amounts would otherwise be recorded to expense or income under GAAP. Refer to "Regulation and Regulated Operations" in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2015, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $9.3 billion and regulatory liabilities (including current balancing accounts payable) of $7.7 billion.

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

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent there is a high degree of uncertainty in the Utility's forecast, it will record a provision based on the lower end of the range of possible losses. The Utility's capital forecasts involve a series of complex judgments regarding detailed project plans, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors. The Utility recorded charges of $407 million in 2015 for estimated capital spending that is probable of disallowance related to the Penalty Decision. Management will continue to evaluate and estimate capital spending that may be probable of disallowance in future periods. These estimates are subject to adjustment based on the final 2015 GT&S rate case decision which is expected in 2016. The Utility also recorded $116 million and $196 million in 2014 and 2013, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. Management will continue to periodically assess its safety-related capital costs and the related CPUC regulatory proceedings, and further charges could be required in future periods.

Loss Contingencies

Environmental Remediation Liabilities

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

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

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

At December 31, 2015 and 2014, the Utility's accruals for undiscounted gross environmental liabilities were $969 million and $954 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.9 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

Legal and Regulatory Matters

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

Asset Retirement Obligations

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

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

At December 31, 2015, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $3.6 billion. Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the ARO. If the inflation adjustment or discount rate increased 25 basis points, the result would be an immaterial impact to ARO.

Pension and Other Postretirement Benefit Plans

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

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

In establishing health care cost assumptions, PG&E Corporation and the Utility consider recent cost trends and projections from industry experts. This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation in health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2015 is 7.2%, gradually decreasing to the ultimate trend rate of 4% in 2024 and beyond.

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed-income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.1% compares to a ten-year actual return of 7.8%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 688 Aa-grade non-callable bonds at December 31, 2015. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

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

(in millions)	Increase (Decrease) in Assumption		Increase in 2015 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2015
Discount rate	(0.50)	%	$ 119	$ 1,227
Rate of return on plan assets	(0.50)	%	70	-
Rate of increase in compensation	0.50	%	59	285

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

(in millions)	Increase (Decrease) in Assumption		Increase in 2015 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2015
Health care cost trend rate	0.50	%	$ 4	$ 56
Discount rate	(0.50)	%	4	123
Rate of return on plan assets	(0.50)	%	10	-

NEW ACCOUNTING PRONOUNCEMENTS

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

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

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

- the timing and outcomes of the 2015 GT&S rate case, the 2017 GRC, the TO rate cases, and other ratemaking and regulatory proceedings;

- the timing and outcomes of the federal criminal prosecution of the Utility, the pending CPUC investigation of the Utility’s natural gas distribution record-keeping practices, the SED’s unresolved enforcement matters relating to the Utility’s compliance with natural gas-related laws and regulations, and the other investigations that have been or may be commenced relating to the Utility’s compliance with natural gas-related laws and regulations, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the timing and outcome of the CPUC’s investigation of communications between the Utility and the CPUC that may have violated the CPUC’s rules regarding ex parte communications or are otherwise alleged to be improper, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the criminal prosecution of the Utility, the state and federal investigations of natural gas incidents, matters relating to the indicted case, improper communications between the CPUC and the Utility; and the Utility’s ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether the Utility can control its costs within the authorized levels of spending, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;

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

- the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

- the outcomes of future investigations or other enforcement proceedings that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

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

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies, including the California State Water Resources Board and the California State Lands Commission, that may affect the Utility's ability to continue operating Diablo Canyon; and whether the Utility decides to resume its pursuit to renew the two Diablo Canyon NRC operating licenses, and if so, whether the licenses are renewed;

- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events;

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

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

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- the impact that reductions in customer demand for electricity and natural gas have on the Utility’s ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility’s business strategy to address the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services is successful;

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

- whether the Utility’s information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility’s security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility’s information technology and operating systems;

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

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

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

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

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see Item. 1A. Risk Factors above and our detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PG&E Corporation

CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share amounts)

	Year ended December 31,		
	2015	2014	2013
Operating Revenues			
Electric	$13,657	$13,658	$12,494
Natural gas	3,176	3,432	3,104
Total operating revenues	16,833	17,090	15,598
Operating Expenses			
Cost of electricity	5,099	5,615	5,016
Cost of natural gas	663	954	968
Operating and maintenance	6,951	5,638	5,775
Depreciation, amortization, and decommissioning	2,612	2,433	2,077
Total operating expenses	15,325	14,640	13,836
Operating Income	1,508	2,450	1,762
Interest income	9	9	9
Interest expense	(773)	(734)	(715)
Other income, net	117	70	40
Income Before Income Taxes	861	1,795	1,096
Income tax (benefit) provision	(27)	345	268
Net Income	888	1,450	828
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	$874	$1,436	$814
Weighted Average Common Shares Outstanding, Basic	484	468	444
Weighted Average Common Shares Outstanding, Diluted	487	470	445
Net Earnings Per Common Share, Basic	$1.81	$3.07	$1.83
Net Earnings Per Common Share, Diluted	$1.79	$3.06	$1.83

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year ended December 31,		
	2015	2014	2013
Net Income	$888	$1,450	$828
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations			
(net of taxes of $0, $10, and $80, at respective dates)	(1)	(14)	113
Net change in investments			
(net of taxes of $12, $17, and $26 at respective dates)	(17)	(25)	38
Total other comprehensive income (loss)	(18)	(39)	151
Comprehensive Income	870	1,411	979
Preferred stock dividend requirement of subsidiary	14	14	14
Comprehensive Income Attributable to Common Shareholders	$856	$1,397	$965

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at December 31,	
	2015	2014
ASSETS		
Current Assets		
Cash and cash equivalents	$123	$151
Restricted cash	234	298
Accounts receivable		
Customers (net of allowance for doubtful accounts of $54 and $66 at respective dates)	1,106	960
Accrued unbilled revenue	855	776
Regulatory balancing accounts	1,760	2,266
Other	286	377
Regulatory assets	517	444
Inventories		
Gas stored underground and fuel oil	126	172
Materials and supplies	313	304
Income taxes receivable	155	198
Other	347	443
Total current assets	5,822	6,389
Property, Plant, and Equipment		
Electric	48,532	45,162
Gas	16,749	15,678
Construction work in progress	2,059	2,220
Other	2	2
Total property, plant, and equipment	67,342	63,062
Accumulated depreciation	(20,619)	(19,121)
Net property, plant, and equipment	46,723	43,941
Other Noncurrent Assets		
Regulatory assets	7,029	6,322
Nuclear decommissioning trusts	2,470	2,421
Income taxes receivable	135	91
Other	1,160	963
Total other noncurrent assets	10,794	9,797
TOTAL ASSETS	$63,339	$60,127

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31, 2015	2014
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$1,019	$633
Long-term debt, classified as current	160	-
Accounts payable		
Trade creditors	1,414	1,244
Regulatory balancing accounts	715	1,090
Other	398	476
Disputed claims and customer refunds	454	434
Interest payable	206	197
Other	1,997	1,846
Total current liabilities	6,363	5,920
Noncurrent Liabilities		
Long-term debt	16,030	15,050
Regulatory liabilities	6,321	6,290
Pension and other postretirement benefits	2,622	2,561
Asset retirement obligations	3,643	3,575
Deferred income taxes	9,206	8,513
Other	2,326	2,218
Total noncurrent liabilities	40,148	38,207
Commitments and Contingencies (Note 13)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 492,025,443 and 475,913,404 shares outstanding at respective dates	11,282	10,421
Reinvested earnings	5,301	5,316
Accumulated other comprehensive (loss) income	(7)	11
Total shareholders' equity	16,576	15,748
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	16,828	16,000
TOTAL LIABILITIES AND EQUITY	$63,339	$60,127

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2015	2014	2013
Cash Flows from Operating Activities			
Net income	$ 888	$ 1,450	$ 828
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,612	2,433	2,077
Allowance for equity funds used during construction	(107)	(100)	(101)
Deferred income taxes and tax credits, net	693	690	1,075
Disallowed capital expenditures	407	116	196
Other	326	286	355
Effect of changes in operating assets and liabilities:			
Accounts receivable	(177)	13	(152)
Inventories	37	(22)	(10)
Accounts payable	(55)	(61)	113
Income taxes receivable/payable	43	376	(363)
Other current assets and liabilities	(315)	205	(469)
Regulatory assets, liabilities, and balancing accounts, net	(244)	(1,642)	(202)
Other noncurrent assets and liabilities	(355)	(67)	80
Net cash provided by operating activities	3,753	3,677	3,427
Cash Flows from Investing Activities			
Capital expenditures	(5,173)	(4,833)	(5,207)
Decrease in restricted cash	64	3	29
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,268	1,336	1,619
Purchases of nuclear decommissioning trust investments	(1,392)	(1,334)	(1,604)
Other	22	114	56
Net cash used in investing activities	(5,211)	(4,714)	(5,107)
Cash Flows from Financing Activities			
Borrowings (repayments) under revolving credit facilities	-	(260)	140
Net issuances (repayments) of commercial paper, net of discount of $3, $2, and $2 at respective dates	683	(583)	542
Proceeds from issuance of short-term debt, net of issuance costs	-	300	-
Short-term debt matured	(300)	-	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $27, $17 and $18 at respective dates	1,123	2,308	1,532
Repayments of long-term debt	-	(889)	(861)
Common stock issued	780	802	1,045
Common stock dividends paid	(856)	(828)	(782)
Other	-	42	(41)
Net cash provided by financing activities	1,430	892	1,575

Net change in cash and cash equivalents	(28)	(145)	(105)
Cash and cash equivalents at January 1	151	296	401
Cash and cash equivalents at December 31	$ 123	$ 151	$ 296

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Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$(684)	$(633)	$(623)
Income taxes, net	77	501	(41)
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	$224	$217	$208
Capital expenditures financed through accounts payable	440	339	322
Noncash common stock issuances	21	21	22
Terminated capital leases	-	71	-

See accompanying Notes to the Consolidated Financial Statements.

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PG&E Corporation

CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except share amounts)

	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity	Non controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2012	430,718,293	$ 8,428	$ 4,747	$ (101)	$ 13,074	$ 252	$ 13,326
Net income	-	-	828	-	828	-	828
Other comprehensive income	-	-	-	151	151	-	151
Common stock issued, net	25,952,131	1,067	-	-	1,067	-	1,067
Stock-based compensation amortization	-	56	-	-	56	-	56
Common stock dividends declared	-	-	(819)	-	(819)	-	(819)
Tax expense from employee stock plans	-	(1)	-	-	(1)	-	(1)
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2013	456,670,424	$ 9,550	$ 4,742	$ 50	$ 14,342	$ 252	$ 14,594
Net income	-	-	1,450	-	1,450	-	1,450
Other comprehensive loss	-	-	-	(39)	(39)	-	(39)
Common stock issued, net	19,242,980	823	-	-	823	-	823
Stock-based compensation amortization	-	65	-	-	65	-	65
Common stock dividends declared	-	-	(862)	-	(862)	-	(862)
Tax expense from employee stock plans	-	(17)	-	-	(17)	-	(17)
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2014	475,913,404	$ 10,421	$ 5,316	$ 11	$ 15,748	$ 252	$ 16,000
Net income	-	-	888	-	888	-	888
Other comprehensive loss	-	-	-	(18)	(18)	-	(18)
Common stock issued, net	16,112,039	801	-	-	801	-	801
Stock-based compensation amortization	-	66	-	-	66	-	66
Common stock dividends declared	-	-	(889)	-	(889)	-	(889)
Tax expense from employee stock plans	-	(6)	-	-	(6)	-	(6)

Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2015	492,025,443	$11,282	$ 5,301	$ (7)	$ 16,576	$ 252	$16,828

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF INCOME

(in millions)

	Year ended December 31,		
	2015	2014	2013
Operating Revenues			
Electric	$13,657	$13,656	$12,489
Natural gas	3,176	3,432	3,104
Total operating revenues	16,833	17,088	15,593
Operating Expenses			
Cost of electricity	5,099	5,615	5,016
Cost of natural gas	663	954	968
Operating and maintenance	6,949	5,635	5,742
Depreciation, amortization, and decommissioning	2,611	2,432	2,077
Total operating expenses	15,322	14,636	13,803
Operating Income	1,511	2,452	1,790
Interest income	8	8	8
Interest expense	(763)	(720)	(690)
Other income, net	87	77	84
Income Before Income Taxes	843	1,817	1,192
Income tax (benefit) provision	(19)	384	326
Net Income	862	1,433	866
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	$848	$1,419	$852

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Year ended December 31,		
	2015	2014	2013
Net Income	$862	$1,433	$866
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations			
(net of taxes of $1, $6, and $75, at respective dates)	(2)	(8)	106
Total other comprehensive income (loss)	(2)	(8)	106
Comprehensive Income	$860	$1,425	$972

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at December 31,	
	2015	2014
ASSETS		
Current Assets		
Cash and cash equivalents	$59	$55
Restricted cash	234	298
Accounts receivable		
Customers (net of allowance for doubtful accounts of $54 and $66 at respective dates)	1,106	960
Accrued unbilled revenue	855	776
Regulatory balancing accounts	1,760	2,266
Other	284	375
Regulatory assets	517	444
Inventories		
Gas stored underground and fuel oil	126	172
Materials and supplies	313	304
Income taxes receivable	130	168
Other	346	409
Total current assets	5,730	6,227
Property, Plant, and Equipment		
Electric	48,532	45,162
Gas	16,749	15,678
Construction work in progress	2,059	2,220
Total property, plant, and equipment	67,340	63,060
Accumulated depreciation	(20,617)	(19,120)
Net property, plant, and equipment	46,723	43,940
Other Noncurrent Assets		
Regulatory assets	7,029	6,322
Nuclear decommissioning trusts	2,470	2,421
Income taxes receivable	135	91
Other	1,053	864
Total other noncurrent assets	10,687	9,698
TOTAL ASSETS	$63,140	$59,865

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31, 2015	2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$1,019	$633
Long-term debt, classified as current	160	-
Accounts payable		
Trade creditors	1,414	1,243
Regulatory balancing accounts	715	1,090
Other	418	444
Disputed claims and customer refunds	454	434
Interest payable	203	195
Other	1,750	1,604
Total current liabilities	6,133	5,643
Noncurrent Liabilities		
Long-term debt	15,680	14,700
Regulatory liabilities	6,321	6,290
Pension and other postretirement benefits	2,534	2,477
Asset retirement obligations	3,643	3,575
Deferred income taxes	9,487	8,773
Other	2,282	2,178
Total noncurrent liabilities	39,947	37,993
Commitments and Contingencies (Note 13)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	7,215	6,514
Reinvested earnings	8,262	8,130
Accumulated other comprehensive income	3	5
Total shareholders' equity	17,060	16,229
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$63,140	$59,865

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2015	2014	2013
Cash Flows from Operating Activities			
Net income	$862	$1,433	$866
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,611	2,432	2,077
Allowance for equity funds used during construction	(107)	(100)	(101)
Deferred income taxes and tax credits, net	714	731	1,103
Disallowed capital expenditures	407	116	196
Other	263	226	299
Effect of changes in operating assets and liabilities:			
Accounts receivable	(177)	16	(152)
Inventories	37	(22)	(10)
Accounts payable	(2)	(55)	99
Income taxes receivable/payable	38	395	(377)
Other current assets and liabilities	(342)	155	(404)
Regulatory assets, liabilities, and balancing accounts, net	(244)	(1,642)	(202)
Other noncurrent assets and liabilities	(340)	(66)	22
Net cash provided by operating activities	3,720	3,619	3,416
Cash Flows from Investing Activities			
Capital expenditures	(5,173)	(4,833)	(5,207)
Decrease in restricted cash	64	3	29
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,268	1,336	1,619
Purchases of nuclear decommissioning trust investments	(1,392)	(1,334)	(1,604)
Other	22	29	21
Net cash used in investing activities	(5,211)	(4,799)	(5,142)
Cash Flows from Financing Activities			
Net issuances (repayments) of commercial paper, net of discount of $3, $2, and $2 at respective dates	683	(583)	542
Proceeds from issuance of short-term debt, net of issuance costs	-	300	-
Short-term debt matured	(300)	-	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $27, $14, and $18 at respective dates	1,123	1,961	1,532
Long-term debt matured or repurchased	-	(539)	(861)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution from PG&E Corporation	705	705	1,140

Other	14	56	(26)
Net cash provided by financing activities	1,495	1,170	1,597
Net change in cash and cash equivalents	4	(10)	(129)
Cash and cash equivalents at January 1	55	65	194
Cash and cash equivalents at December 31	$59	$55	$65

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Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$(675)	$(618)	$(600)
Income taxes, net	77	500	(62)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	$440	$339	$322
Terminated capital leases	-	71	-

See accompanying Notes to the Consolidated Financial Statements.

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Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions)

	Preferred Stock	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2012	$ 258	$ 1,322	$ 4,682	$ 7,291	$ (93)	$ 13,460
Net income	-	-	-	866	-	866
Other comprehensive income	-	-	-	-	106	106
Equity contribution	-	-	1,140	-	-	1,140
Tax expense from employee stock plans	-	-	(1)	-	-	(1)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2013	$ 258	$ 1,322	$ 5,821	$ 7,427	$ 13	$ 14,841
Net income	-	-	-	1,433	-	1,433
Other comprehensive loss	-	-	-	-	(8)	(8)
Equity contribution	-	-	705	-	-	705
Tax expense from employee stock plans	-	-	(12)	-	-	(12)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2014	$ 258	$ 1,322	$ 6,514	$ 8,130	$ 5	$ 16,229
Net income	-	-	-	862	-	862
Other comprehensive loss	-	-	-	-	(2)	(2)
Equity contribution	-	-	705	-	-	705
Tax expense from employee stock plans	-	-	(4)	-	-	(4)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2015	$ 258	$ 1,322	$ 7,215	$ 8,262	$ 3	$ 17,060

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's consolidated financial statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying consolidated financial statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the consolidated financial statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation and Regulated Operations

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

The Utility also records a regulatory balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund. In addition, the Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. These differences have no impact on net income. (See “Revenue Recognition” below.)

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

Revenue Recognition

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

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

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred.

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

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 13 below.)

Allowance for Doubtful Accounts Receivable

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

Inventories

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

Emission Allowances

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

Property, Plant, and Equipment

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

	Estimated Useful	Balance at December 31,	
(in millions, except estimated useful lives)	Lives (years)	2015	2014
Electricity generating facilities (1)	5 to 100	$9,860	$9,374
Electricity distribution facilities	15 to 55	28,476	26,633
Electricity transmission facilities	15 to 75	10,196	9,155
Natural gas distribution facilities	5 to 60	10,397	9,741
Natural gas transportation and storage facilities	5 to 65	6,352	5,937
Construction work in progress		2,059	2,220
Total property, plant, and equipment		67,340	63,060
Accumulated depreciation		(20,617)	(19,120)
Net property, plant, and equipment		$46,723	$43,940

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

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's composite depreciation rates were 3.80% in 2015, 3.77% in 2014, and 3.51% in 2013. The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $48 million and $107 million during 2015, $45 million and $100 million during 2014, and $47 million and $101 million during 2013.

Asset Retirement Obligations

The following table summarizes the changes in ARO liability during 2015 and 2014, including nuclear decommissioning obligations:

(in millions)	2015	2014
ARO liability at beginning of year	$3,575	$3,538
Revision in estimated cash flows	13	(16)
Accretion	169	163
Liabilities settled	(114)	(110)
ARO liability at end of year	$3,643	$3,575

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

Nuclear Decommissioning Obligation

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are generally conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment.

The Utility adjusts its nuclear decommissioning obligation to reflect changes in the estimated costs of decommissioning its nuclear power facilities and records this as an adjustment to the ARO liability on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $2.5 billion at December 31, 2015 and 2014. The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $3.5 billion at December 31, 2015 and 2014 (or $6.1 billion in future dollars). These estimates are based on the 2012 decommissioning cost studies, prepared in accordance with CPUC requirements.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. The Utility recorded charges of $407 million in 2015 for estimated capital spending that is probable of disallowance related to the Penalty Decision and $116 million and $196 million in 2014 and 2013, respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (See "Enforcement and Litigation Matters" in Note 13 below).

Nuclear Decommissioning Trusts

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

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

Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2015, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2015, it did not consolidate any of them.

Other Accounting Policies

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For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies and Commitments" in Note 13 of the Notes to the Consolidated Financial Statements.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2015 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
Beginning balance	$ (21)	$ 15	$ 17	$ 11
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss				
(net of taxes of $51, $21, and $0, respectively)	(76)	(31)	-	(107)
Regulatory account transfer				
(net of taxes of $51, $21, and $0, respectively)	73	31	-	104
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $7, $8, and $0, respectively) (1)	8	11	-	19
Amortization of net actuarial loss				
(net of taxes of $4, $1, and $0, respectively) (1)	6	3	-	9
Regulatory account transfer				
(net of taxes of $10, $9, and $0, respectively) (1)	(13)	(13)	-	(26)
Realized gain on investments				
(net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive loss	(2)	1	(17)	(18)
Ending balance	$ (23)	$ 16	$ -	$ (7)

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

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2014 consisted of the following:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
Beginning balance	$ (7)	$ 15	$ 42	$ 50
Other comprehensive income before reclassifications:				
Change in investments				
(net of taxes of $0, $0, and $4, respectively)	-	-	5	5
Unrecognized net actuarial loss				
(net of taxes of $404, $19, and $0, respectively)	(588)	(28)	-	(616)
Unrecognized prior service cost				
(net of taxes of $0, $0, and $0, respectively)	1	-	-	1
Regulatory account transfer				
(net of taxes of $394, $19, and $0, respectively)	573	28	-	601
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $8, $9, and $0, respectively) (1)	12	14	-	26
Amortization of net actuarial loss				
(net of taxes of $1, $1, and $0, respectively) (1)	1	1	-	2
Regulatory account transfer				
(net of taxes of $9, $10, and $0, respectively) (1)	(13)	(15)	-	(28)
Realized gain on investments				
(net of taxes of $0, $0, and $20, respectively)	-	-	(30)	(30)
Net current period other comprehensive loss	(14)	-	(25)	(39)
Ending balance	$ (21)	$ 15	$ 17	$ 11

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

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

New Accounting Pronouncements

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, which amends guidance to help improve the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes, which amends existing guidance on the presentation of deferred income tax assets and liabilities. The amendments in the ASU require that all deferred tax liabilities and assets be classified as noncurrent on the balance sheet. This ASU will be effective for PG&E Corporation and the Utility on January 1, 2017, with earlier adoption permitted. PG&E Corporation and the Utility have implemented this standard as of the year ended December 31, 2015 on a prospective basis and the prior periods have not been retrospectively adjusted.

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Fair Value Measurement

In May 2015, the FASB issued ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which removes the requirement to categorize within the fair value hierarchy all investments measured using net asset value per share as a practical expedient. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016. This standard will be adopted for related disclosures in the first quarter of 2016 and will not have an impact on the consolidated financial statements.

Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU No. 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement, which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. The ASU became effective for PG&E Corporation and the Utility on January 1, 2016. PG&E Corporation and the Utility have determined that this ASU will not impact their consolidated financial statements and related disclosures and will adopt this standard starting in the first quarter of 2016.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs, which amends existing presentation of debt issuance costs. PG&E Corporation and the Utility currently disclose debt issuance costs in current assets – other and noncurrent assets – other. The amendments in this ASU, that became effective for PG&E Corporation and the Utility on January 1, 2016, require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility will adopt this standard in the first quarter of 2016 and do not expect the reclassification to have a material impact on their consolidated financial statements.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which amends existing revenue recognition guidance. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, deferring the effective date of this amendment for PG&E

Corporation and the Utility by one year to January 1, 2018, with early adoption permitted as of the original effective date of January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are comprised of the following:

	Balance at December 31,		Recovery
(in millions)	2015	2014	Period
Pension benefits (1)	$2,414	$2,347	Indefinitely (4)
Deferred income taxes (1)	3,054	2,390	47 years
Utility retained generation (2)	411	456	10 years
Environmental compliance costs (1)	748	717	32 years
Price risk management (1)	138	127	10 years
Electromechanical meters (3)	-	70	-
Unamortized loss, net of gain, on reacquired debt (1)	94	113	11 years
Other	170	102	Various
Total long-term regulatory assets	$7,029	$6,322	

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

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

(3) Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices. As of December 31, 2015, the remaining balance of $70 million is included in current regulatory assets on the Consolidated Balance Sheets.

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

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

Regulatory Liabilities

Current Regulatory Liabilities

At December 31, 2015 and 2014, the Utility had current regulatory liabilities of $676 million and $261 million, respectively. At December 31, 2015, the current regulatory liabilities consisted primarily of a $400 million bill credit to the Utility's natural gas customers resulting from the Penalty Decision. (See Note 13 below.) Current regulatory liabilities are included within current liabilities-other in the Consolidated Balance Sheets.

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Long -Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	2015	2014
Cost of removal obligations (1)	$4,605	$4,211
Recoveries in excess of AROs (2)	631	754
Public purpose programs (3)	600	701
Other	485	624
Total long-term regulatory liabilities	$6,321	$6,290