PG&E Corp
Form 10-K
February 10, 2015

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

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2014
Or

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

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

Title of each 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 þ No o
Pacific Gas and Electric Company	Yes þ No o

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 o No þ
Pacific Gas and Electric Company	Yes o No þ

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 þ No o
Pacific Gas and Electric Company	Yes þ No o

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 þ	No o
Pacific Gas and Electric Company	Yes þ	No o

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	þ
Pacific Gas and Electric Company	þ

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 þ	Large accelerated filer o
Accelerated filer o	Accelerated filer o
Non-accelerated filer o	Non-accelerated filer þ
Smaller reporting company o	Smaller reporting company o

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 o No þ
Pacific Gas and Electric Company	Yes o No þ

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2014, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$22,602 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of January 27, 2015:

PG&E Corporation:	476,399,910
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 2015 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

Contents

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.

2014 Annual Report	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2014, including the information incorporated by reference into the report
AB	Assembly Bill
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
ARO	asset retirement obligation
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
Central Coast Board	Central Coast Regional Water Quality Control Board
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
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
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD
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

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. 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. PG&E Corporation's and the Utility's operating revenues, income, and total assets can be found 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, 2014, PG&E Corporation and its subsidiaries had 22,581 employees, including 22,569 employees of the Utility. Of the Utility's regular employees, 13,649 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 two agreements with IBEW, and the single agreement with ESC, will expire on December 31, 2015. The SEIU collective bargaining agreement will expire on July 31, 2015.

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.

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 Item 7. MD&A. In particular, PG&E Corporation's and the Utility's financial results are expected to be materially affected by the final outcome of the CPUC's pending investigative enforcement proceedings against the Utility. These investigations relate to (1) the Utility's safety recordkeeping 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, recordkeeping 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. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by the costs the Utility has incurred related to shareholder funded safety work, the ongoing regulatory investigations, and civil lawsuits that commenced following the San Bruno accident. In addition, PG&E Corporation's and the Utility's financial results could be materially affected by the outcome of the federal criminal prosecution of the Utility and the other enforcement matters discussed in "Enforcement and Litigation Matters" in Item 7. MD&A.

Regulatory Environment

The Utility's business is subject to a complex set of energy, environmental and other laws, regulations, and regulatory proceedings at the federal, state, and local levels. This section and the “Ratemaking Mechanisms” section below summarize some of the more significant laws, regulations, and regulatory proceedings affecting the Utility. See “Enforcement and Litigation Matters” and “Ratemaking and Other Regulatory Proceedings” in Item 7. MD&A for discussion of specific pending regulatory matters that are expected to materially affect PG&E Corporation and 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 California 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, and the development of energy storage technologies and facilities. In addition, 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 enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility electric and gas facilities. The CPUC also has authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has adopted a gas safety enforcement program and authorized the SED to issue citations and impose fines for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. (See “Enforcement and Litigation Matters” in Item 7. MD&A for information about the presiding officer decisions issued in the three CPUC investigative enforcement proceedings pending against the Utility and SED’s enforcement actions taken against the Utility.) In December 2014, the CPUC also adopted an interim electric safety enforcement program that became effective January 1, 2015. (On January 7, 2015, the Utility requested that the CPUC reconsider this decision.) Under both the gas and electric programs, the SED can impose fines up to $50,000 per violation, per day. The CPUC is expected to review both safety programs during 2015 to determine whether any further changes are needed.

In addition, the CPUC conducts audits and reviews of the Utility’s accounting, performance and compliance with regulatory guidelines, as well as investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies. The CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation’s Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see “Liquidity and Financial Resources” in Item 7. MD&A and Item 1A. Risk Factors.)

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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 interconnections of transmission systems with other electric systems and generation facilities, 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 transmission system in California and provides open access transmission service on a nondiscriminatory 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 "Electric Generation 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.

Other Regulation

The California Energy Resources Conservation and Development Commission, commonly called 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 to 1990 levels by 2020. (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 roads. In exchange for the right to use public streets and roads, 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.

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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 various 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 (maintenance, administration and general expenses) and capital costs (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, 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 Impact Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

To develop retail rates, authorized revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Rate changes become effective prospectively on or after the date of CPUC or FERC decisions.

California AB 327, which became effective on January 1, 2014, repealed prior law that restricted the CPUC's ability to change residential electric rates and to reduce the level of rate assistance for certain low-income customers. AB 327 also authorized the CPUC to approve fixed charges to be collected from residential customers. In 2012, the CPUC opened a rulemaking proceeding to examine residential rate design in California that, consistent with AB 327, allows the CPUC to simplify the rate structure to bring marginal rates closer to reflecting the Utility's actual costs. In February 2014, as ordered by the CPUC, the Utility submitted a long-term residential rate reform plan that proposes a fixed customer charge, gradual flattening of the tiered rate structure, and an optional time-of-use rate. The CPUC is expected to issue a final decision by the summer of 2015.

AB 327 also requires the CPUC to develop a new structure for net energy metering by December 31, 2015, that must be implemented no later than July 1, 2017. California's net energy metering program currently allows customers installing renewable distributed generation to receive bill credits for power delivered to the grid at their full retail rate. Increasing levels of self-generation of electricity by customers, coupled with net metering and retail rates that do not reflect the Utility's cost structure, has shifted costs to the remaining customers. AB 327 gives the CPUC new authority to reduce the cost shift associated with renewable distributed generation through residential rate and net energy metering reform. In July 2014, the CPUC began a rulemaking proceeding to develop a successor to the existing net energy metering program to comply with the requirements of AB 327. The CPUC is expected to issue a proposed decision in the fall of 2015.

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Results of Operations" in Item 7. MD&A.)

Base Revenues

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs, including return on rate base, related to its electricity and 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 adjustments") in revenue requirements for the subsequent years of the GRC period. Attrition rate adjustments are generally provided for cost increases related to inflation and increases in invested capital. 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.

On August 14, 2014, the CPUC issued a decision in the Utility's 2014 GRC, authorizing the Utility to collect a total 2014 revenue requirement of approximately $7.1 billion to recover anticipated costs associated with electric generation, as well as electric and natural gas distribution (See "Results of Operations" in Item 7. MD&A.) The CPUC also authorized attrition increases of $324 million for 2015 and $371 million for 2016.

On December 9, 2014, the CPUC issued a decision adopting a risk-based decision-making framework for the CPUC to use in evaluating future major rate cases. The CPUC ordered the utilities to file an application on May 1, 2015, to initiate a new proceeding called the Safety Model Assessment Proceeding in which the CPUC will review the models the utilities use to assess and prioritize risks. After this proceeding concludes, each utility would file an application to initiate the first phase of their next GRC. In this phase, known as the Risk Assessment Mitigation Phase, the CPUC will examine the utility's assessment of its key risks and its proposed programs for mitigating those risks.

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 December 2013, the Utility filed its 2015 GT&S rate case application (covering 2015 through 2017) requesting the CPUC approve a total annual revenue requirement of $1.29 billion for anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2015. See "Ratemaking and Other Regulatory Proceedings – 2015 GT&S Rate Case" in Item 7. MD&A for additional information.

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 2016, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also authorized the Utility to earn a 10.40% ROE effective January 1, 2013, compared to the 11.35% previously authorized. The Utility's ROE can be automatically adjusted if the utility bond index changes by certain thresholds on an annual basis. The index changes to date have not exceeded the threshold so the 2015 ROE has remained at 10.40%. The Utility's next cost of capital application is due in April 2016.

Electricity Transmission Owner Rate Cases

The FERC determines the amount of authorized revenue requirement, including rate of return on electric transmission assets, that the Utility may collect in rates in the TO tariff rate case. The Utility generally files a TO tariff rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers. (See "Ratemaking and Other Regulatory Proceedings – FERC Transmission Owner Rate Cases" in Item 7. MD&A.) The Utility also recovers 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 in 1998. 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 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. In January 2012, the CPUC approved the Utility's procurement plan (covering 2012 through 2020).

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. Costs associated with electricity purchases may be disallowed if they are not in compliance with the CPUC-approved plan or if the utility failed to follow the principles of least-cost dispatch. The Utility recovers its electricity procurement costs annually through the energy resource recovery account ("ERRA"). (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 costs, and generation fuel expense and approves a forecasted revenue requirement. The CPUC may adjust a utility's retail electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues. The CPUC performs an annual compliance review of the transactions recorded in the ERRA.

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, the renewable energy mandate, and resource adequacy requirements. See "Electric Utility Operations – Electricity Resources" below as well as Note 14 of the Notes to the Consolidated Financial Statements in Item 8 for additional information.

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 subject to limits as set forth in its Core Procurement Incentive Mechanism ("CPIM"). 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 rates. This is accomplished through monthly advice letters that are effective upon filing. 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 CPIM protects the Utility against after-the-fact reasonableness reviews of these gas procurement costs. Under the CPIM, 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 incentive 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.

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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. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process, 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. The Utility files an application with the CPUC every three years requesting approval of the Utility’s estimated decommissioning costs and authorization to recover the estimated costs through rates. Nuclear decommissioning charges collected through rates are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit.

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.

During 2014, the Utility continued to make improvements to its electric transmission and distribution systems to accommodate the integration of new renewable energy resources, distributed generation resources, and energy storage facilities, and to help create a platform for the development of new Smart Grid technologies. The Utility plans to continue making similar improvements in 2015. In December 2014, the CPUC issued a decision that permits the California investor-owned electric utilities to own EV retail charging equipment in their respective service territories to help meet the state’s goal of reducing GHG emissions by promoting cleaner transportation. On February 9, 2015, the Utility filed an application to request that the CPUC approve the Utility’s proposal to develop, maintain, and operate an EV-charging infrastructure in its service territory. (For more information about the Utility’s application, see “Ratemaking And Other Regulatory Proceedings” in Item 7. MD&A.)

Electricity Resources

The Utility is required to maintain physical 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 2014 represented by each major electricity resource, and further discussed below.

Total 2014 Actual Electricity Generated and Procured – 74,547 GWh (1):

	Percent of Bundled Retail Sales	
Owned Generation Facilities		
Nuclear	20.6%	
Small Hydroelectric	0.8%	
Large Hydroelectric	6.6%	
Fossil fuel-fired	7.4%	
Solar	0.4%	
Total		35.8%
Qualifying Facilities		
Renewable	3.7%	
Non-Renewable	8.5%	
Total		12.2%
Irrigation Districts and Water Agencies		
Small Hydroelectric	0.1%	
Large Hydroelectric	0.8%	
Total		0.9%
Other Third-Party Purchase Agreements		
Renewable	22.0%	
Large Hydroelectric	0.9%	
Non-Renewable	6.6%	
Total		29.5%
Others, Net (2)		21.6%
Total (3)		100.0%

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

Renewable Energy Resources. California law requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers to at least 33% of their total annual retail sales. This program, known as the RPS program, became effective in December 2011, established three multi-year compliance periods that have gradually increasing RPS targets: 2011 through 2013, 2014 through 2016, and 2017 through 2020. After 2020, the RPS compliance periods will be annual.

Renewable generation resources, for purposes of the RPS program, include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 2014, 27% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 22% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (3.8%), the Utility's small hydroelectric facilities (0.8%), and the Utility's solar facilities (0.5%).

The total 2014 renewable deliveries shown above were comprised of the following:

Type	GWh	Percent of Bundled Retail Sales	
Biopower	3,458	4.6	%
Geothermal	3,867	5.2	%
Wind	5,399	7.2	%
RPS-Eligible Hydroelectric	981	1.3	%
Solar	6,478	8.7	%
Total	20,183	27.0	%

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 has an 80.5 MW of energy storage target to meet its 2014 energy storage plan. In December 2014, the Utility held its first competitive request for two types of proposals: (1) an energy storage agreement with the owner of an energy storage facility that would enable the Utility to offer stored energy into the CAISO market and (2) a purchase and sale agreement under which the counterparty would build a storage facility and transfer the facility to the Utility provided the facility meets certain operational conditions. Offers are due by February 17, 2015. The Utility intends to complete negotiations and execute contracts by October 1, 2015 and to submit the executed contracts for CPUC approval by December 1, 2015.

Owned Generation Facilities. At December 31, 2014, 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	2,677
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	7,684

(1) The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the year ended December 31, 2014, the Utility’s Diablo Canyon power plant achieved an average overall capacity factor of approximately 87%. The ability of the Utility to produce nuclear generation depends on the availability of nuclear fuel. The Utility has entered into various purchase agreements for nuclear fuel that are intended to ensure long-term fuel supply. (See Note 14 to the Consolidated Financial Statements in Item 8.) The Diablo Canyon power plant refueling outages are typically scheduled every 20 months. The average length of a refueling outage over the last five years has been approximately 49.5 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors. The NRC operating licenses for the two operating units at Diablo Canyon include various license conditions related to seismic design and safety. The current licenses expire in 2024 and 2025. In November 2009, the Utility filed an application with the NRC to seek the renewal of the 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 that confirmed the seismic safety of the plant. The Independent Review Panel is providing comments on the report and the Utility expects its review to be completed within the next six to eight months. (See also “Environmental Matters” 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 three 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 14 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2014, the Utility owned approximately 18,100 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 November 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 2014, 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 141,700 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 55 transmission switching substations, and 603 distribution substations, with a capacity of approximately 30,200 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 October 2014, the Utility commenced operations at the first of three new electric distribution control centers. This 24,000-square foot, state-of-the-art facility, located in Fresno, California, will enhance electric reliability and resiliency for the Utility's customers throughout the Central Valley and will utilize current and future Smart Grid technologies. Additional facilities in Rocklin and Concord, California, are expected to be completed in 2015 and 2016, respectively. These control centers form a key part of the Utility's efforts to create a smarter, more resilient grid.

In 2014, the Utility replaced approximately 295,000 feet of underground cable, replaced approximately 975,000 feet of overhead wire, and 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 2015.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2012 to 2014 for electricity sold or delivered, including the classification of revenues by type of service.

	2014	2013	2012
Customers (average for the year)	5,276,025	5,243,216	5,214,170
Deliveries (in GWh) (1)	86,303	86,513	86,113
Revenues (in millions):			
Residential	$4,784	$5,091	$4,953
Commercial	5,141	4,905	4,735
Industrial	1,543	1,388	1,408
Agricultural	1,172	1,021	901
Public street and highway lighting	79	75	79
Other (2)	(172)	(128)	(11)
Subtotal	12,547	12,352	12,065
Regulatory balancing accounts (3)	1,109	137	(51)
Total operating revenues	$13,656	$12,489	$12,014
Selected Statistics:			
Average annual residential usage (kWh)	6,458	6,752	5,961
Average billed revenues per kWh:			
Residential	$0.1603	$0.1643	$0.1594
Commercial	0.1585	0.1499	0.1449
Industrial	0.0998	0.0928	0.917
Agricultural	0.1516	0.1454	0.1458
Net plant investment per customer	$6,339	$6,002	$4,919

(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. The 2014 activity represents an increase to balancing account receivable primarily related to the adoption of the 2014 GRC.

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 2014, the Utility purchased approximately 269,590 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 2014.

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, 2014, the Utility’s natural gas system consisted of approximately 42,700 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility’s pipelines. The Utility’s backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility’s interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility’s local transmission and distribution systems.

The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. 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 14 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.

The Utility also owns and operates a 42,000-square-foot control center in San Ramon, California to monitor and control all aspects of its natural gas system across its service area.

During 2014, the Utility completed its system-wide replacement of 847 miles of cast iron natural gas distribution pipeline with plastic pipe. Additionally, the Utility conducted an annual system-wide review of its transmission pipeline class location designations. As part of its distribution integrity management program, during 2014 the Utility completed inspections of approximately 35,000 sewer laterals.

Since work began on the PSEP and other gas transmission work in 2011, the Utility has validated the maximum allowable operating pressure for all of its transmission pipelines through records verification; accomplished four-year goal of strength testing or records validation of 783 miles of transmission pipeline; replaced 127 miles of transmission pipeline; automated 208 valves; and collected and digitized more than 3.8 million pipeline records.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2012 through 2014 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

	2014	2013	2012
Customers (average for the year)	4,394,283	4,378,797	4,353,278
Gas purchased (MMcf)	202,215	240,414	247,792
Average price of natural gas purchased	$4.09	$3.29	$2.45
Bundled gas sales (MMcf):			
Residential	143,514	181,775	185,376
Commercial	42,080	46,668	47,341
Total Bundled Gas Sales	185,594	228,443	232,717
Revenues (in millions):			
Bundled gas sales:			
Residential	$1,683	$1,870	$1,852
Commercial	419	395	383
Other	51	44	66
Bundled gas revenues	2,153	2,309	2,301
Transportation service only revenue	662	555	499
Subtotal	2,815	2,864	2,800
Regulatory balancing accounts	617	240	221
Total operating revenues	$3,432	$3,104	$3,021
Selected Statistics:			
Average annual residential usage (Mcf)	34	44	45
Average billed bundled gas sales revenues per Mcf:			
Residential	$11.72	$10.29	$9.99
Commercial	9.96	8.47	8.09
Net plant investment per customer	$2,468	$2,234	$1,696

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Competition

Competition in the Electricity Industry

California law allows qualifying non-residential customers of investor-owned electric utilities to purchase electricity from energy service providers other than the regulated utilities, (referred to as “direct access”) up to certain annual and overall GWh limits that have been specified for each utility.

The Utility’s customers may, under certain circumstances, obtain power from a CCA instead of from the Utility. California law permits cities and counties and certain other public agencies to generate and/or purchase electricity for their local residents and businesses after they have registered as CCAs and submitted an Implementation Plan to the CPUC. Under these arrangements, the Utility continues to provide transmission, distribution, metering, and billing services to the customers of the CCAs and remains the electricity provider of last resort for those customers. The law provides that a CCA can procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The Utility is able to recover from each CCA any costs of implementing the program that are reasonably attributable to the CCA, and to recover from all customers any costs of implementing the program not reasonably attributable to a CCA.

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, seek to acquire the Utility’s distribution facilities, either under a consensual transaction, or via eminent domain.

The Utility is also subject to increased competition due to 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.

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 monoxide (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 has recovered 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 14: 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 (CERCLA). 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 CERCLA 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 14: Commitments and Contingencies–Environmental Remediation Contingencies, 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 United States 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 January 2014, the EPA published draft regulations under section 111(b) of the Clean Air Act to control CO–2, the most common GHG, from new fossil fuel-fired power plants. While these draft regulations as presently written do not apply to the Utility’s power plants, it is possible that the final regulations may affect the design, construction, operation and cost of future fossil fuel-fired power plants. The EPA is expected to issue final regulations in 2015.

In June 2014, the EPA published draft federal regulations under section 111(d) of the Clean Air Act that are designed to reduce CO2 emissions from existing fossil fuel-fired power plants on a national basis by as much as 30% by 2030, compared with 2005 levels. The EPA is expected to issue final regulations in 2015. As proposed, once the EPA has finalized regulations, states have up to two or three years to submit final plans depending on whether they work alone or in partnership with other states, and up to 15 years for full implementation of all emission reduction measures. 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. 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 law requires the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to implement AB 32, 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. 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 2014, 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 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'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 potential at coastal and low elevation facilities due to sea level rise.

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 also adopting strategies such as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and developing new modeling tools for forecasting runoff.

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 replace a substantial portion of its older cast iron, steel and plastic distribution pipelines and steel gas transmission mains with new pipe, which reduces leakage.

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 2013 totaled more than 57 million metric tonnes of CO–2-e, two-thirds of which came from natural gas use. The following table shows the 2013 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)	2,382,463
Natural Gas Compressor Stations (2)	325,701
Distribution Fugitive Natural Gas Emissions	213,858
Customer Natural Gas Use (3)	43,506,493

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations.
(2) Includes compressor stations emitting more than 25,000 metric tonnes of CO2-e annually.
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, including entities that have their own compliance obligation under AB 32. The Utility's compliance obligation under AB 32 (discussed above under "State Regulation") applies to the combustion of natural gas delivered to customers other than customers that have their own compliance obligation. Excluding the GHG emissions of entities that have their own compliance obligation, the Utility's GHG emissions for 2013 were approximately 19 million metric tonnes, 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 2013 as compared to the national and California averages for electric utilities:

	Amount (Pounds of CO2 per MWh)
U.S. Average (1)	1,232
California's Average (1)	611
Pacific Gas and Electric Company (2)	427

(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 36.4% of the Utility's delivered electricity in 2013. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

	2013	2012
Total NOx Emissions (tons)	153	158
NOx Emissions Rate (pounds/MWh)	0.01	0.01
Total SO2 Emissions (tons)	17	15
SO2 Emissions Rate (pounds/MWh)	0.0011	0.0009

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. The federal regulations provide more flexibility in complying with some of the Clean Water Act's requirements. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Fourth Circuit. California's once-through cooling policy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, 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%. The California Water Board has 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 expected to issue a final decision regarding Diablo Canyon's compliance with the state policy in 2015. 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 such time as 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 2013 and 2014, the Utility was awarded an additional $50 million for costs incurred between 2011 and July 2014. 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 are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. (Also see Cautionary Language Regarding Forward-Looking Statements in Item 7. MD&A.) In addition to other disclosures within this Form 10-K, including MD&A in Item 7 and Note 2: Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements in Item 8 and other documents filed with the SEC from time to time, the following key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility. Such factors could affect actual results of operations and cause results to differ substantially from historical results or from results that are currently sought.

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

PG&E Corporation's and the Utility's financial results could be materially affected by the outcomes of the CPUC investigative enforcement proceedings pending against the Utility, the federal criminal prosecution of the Utility, and the investigations and other potential enforcement matters discussed in Item 7. MD&A.

In September 2014, the CPUC ALJs overseeing the three investigative enforcement proceedings against the Utility issued a decision to impose total penalties of $1.4 billion on the Utility based on their findings that the Utility committed approximately 3,700 violations of natural gas regulations. The Utility and other parties have appealed these decisions. (See "Enforcement and Litigation Matters – Pending CPUC Investigations" in Item 7. MD&A.) The CPUC could issue a final decision that imposes a materially higher amount of penalties. The impact on PG&E Corporation's and the Utility's consolidated financial statements will vary depending on the forms and amounts of penalties imposed.

Further, if the Utility is convicted of the pending federal criminal charges, the Utility could be required to pay a material amount of fines. Based on the superseding indictment's allegations, the maximum alternative fine would be approximately $1.13 billion. (See "Enforcement and Litigation Matters – Federal Criminal Indictment" in Item 7. MD&A.) The Utility also could incur a material amount of costs to comply with remedial measures that the CPUC or a federal judge may impose on the Utility, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor.

The CPUC could impose penalties or take other enforcement action with respect to communications that may have violated the CPUC's rules regarding ex parte communications (See "Enforcement and Litigation Matters – Improper CPUC Communications" in Item 7. MD&A.) In response to the Utility's violations of the CPUC's rules regarding ex parte communications relating to the 2015 GT&S rate case, the CPUC issued a decision to disallow up to the entire amount of incremental revenues that would have been collected from ratepayers over the five-month period between March 2015 and August 2015. The exact amount of the revenue disallowance will be determined in the CPUC's final decision in the 2015 GT&S rate case. See "Ratemaking and Other Regulatory Proceedings – 2015 Gas Transmission and Storage Rate Case" in Item 7. MD&A. Federal and state law enforcement authorities have begun investigations in connection with these matters and they could take enforcement action in the future. The Utility could be subject to additional penalties or reputational harm if it fails to comply with the restrictions on communications between the Utility and the CPUC imposed by the CPUC in November 2014.

In addition, the Utility could incur material charges, including fines and other penalties, in connection with the new CPUC investigation of the Utility's compliance with natural gas distribution record-keeping practices, the self-reports the Utility has submitted to the CPUC in accordance with the SED's gas safety citation program, the SED's audit findings, the other matters discussed in "Enforcement and Litigation Matters" in Item 7. MD&A, and other self-reports the Utility may file under the gas safety program or under the new electric safety program.

The Utility could be subject to additional regulatory or governmental enforcement action 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 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 financial results depend upon the amount of revenues the Utility is authorized to collect through rates and the Utility's ability to manage its operating expenses 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 and of its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; general economic conditions and 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. As the Utility's reputation continues to suffer from the negative media coverage of the ongoing enforcement proceedings, the risk of adverse regulatory outcomes may increase. In addition, the restrictions on communications between the Utility and the CPUC imposed by the CPUC in November 2014 prevent the Utility from fully participating in the regulatory process, which, in turn may affect regulatory outcomes. The Utility's relationship with the CPUC also may be negatively affected depending on what, if any, future action may be taken, or negative media coverage that may be generated, in response to the release of approximately 65,000 emails between the Utility and the CPUC to the CPUC and the City of San Bruno.

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 the economy's corresponding 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. Further, should the deployment of new electricity generation and energy storage technologies spread and become more cost-effective, the Utility's ability to recover its investments and earn its authorized ROE could be adversely affected unless rates are appropriately adjusted. Also, 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.

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 and whether the Utility is able to continue using regulatory accounting for its natural gas transmission business.

The Utility's ability to recover its natural gas transmission and storage costs in 2015, 2016, and 2017 and earn its authorized ROE will be materially affected by the amount of revenues the CPUC ultimately authorizes the Utility to collect in the 2015 GT&S rate case proceeding. (See "Ratemaking and Other Regulatory Proceedings" in Item 7. MD&A.) In addition, the Utility plans to perform certain work during 2015 through 2017, including work to complete projects under the PSEP and to identify and remove encroachments from gas transmission pipeline rights-of-way. The Utility has not sought to recover the costs it incurs to perform this work. Actual costs to perform this work could materially exceed forecasts and negatively affect PG&E Corporation's and the Utility's results of operations. The Utility expects that it will continue to incur costs to respond to public opposition to the Utility's work to remove trees and other encroachments. The media attention to the Utility's encroachment work also may negatively affect the Utility's reputation.

If rates in the 2015 GT&S rate case and future rate cases are not set at a level that allows the Utility to recover the cost of providing natural gas transmission service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting to its natural gas transmission business. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8 as well as "Critical Accounting Policies" in Item 7. MD&A.) If that occurs, the regulatory assets and liabilities that do not qualify for regulatory accounting treatment would be charged against income in the period in which that determination was made and these charges could have a material impact on PG&E Corporation's and the Utility's financial results. In addition, 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 gain recognition.

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 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 generation providers. Despite original CPUC approval of the contracts, the CPUC could disallow contract costs if it determines that the costs are unreasonably above market. The Utility also could incur a CPUC disallowance and/or liability to the counterparties under its contracts to procure electricity from conventional and renewable generation resources if such resources are physically curtailed by the CAISO during periods of over-generation when generation resources scheduled with the CAISO exceed customer load.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by the whether the wholesale electricity market in California 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 Electric 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 its procurement costs. Although the Utility is permitted to collect non-bypassable charges for generation-related costs incurred on behalf of former customers, as well as charges for distribution, metering, or other services the Utility continues to provide to such customers, the charges may not be sufficient for the Utility to fully recover the costs to provide these services. 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, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, could put upward rate pressure on remaining customers. Also, 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.

PG&E Corporation's and the Utility's financial results could be materially affected 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.

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's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend on many factors, including the ultimate outcome of the matters discussed under "Enforcement and Litigation Matters" in Item 7. MD&A., the ultimate amount of costs the Utility incurs but does not recover through rates, and the outcome of pending and future ratemaking proceedings. These outcomes in turn can affect PG&E Corporation's and the Utility's credit ratings and outlook. 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 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, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about the CPUC investigations, the criminal investigations, the criminal prosecution, and the other pending enforcement matters. Their negative reputations and continuing uncertainty surrounding 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. Declines in the stock price would increase the dilutive effect of future stock issuances and make it more difficult or expensive for PG&E Corporation to complete future equity offerings.

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.

Depending on the outcome of the CPUC investigations, criminal prosecution, and other enforcement matters pending against the Utility, future issuances of PG&E Corporation common stock may 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 operations of the Utility's electricity and natural gas generation, transmission, and distribution facilities is inherently dangerous and involves significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial results, and 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 "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 (such as the San Bruno accident discussed in Item 7. MD&A.);
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
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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;

- 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;

- construction performed by third parties, such as ground excavation or "dig-ins" that damage the Utility's underground facilities;

- the release of hazardous or toxic substances into the air, water, or soil; 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, to compensate third parties, or to pay penalties or implement remedial measures. These costs may not be recoverable through rates or insurance and could have a material impact of PG&E Corporation's financial results and reputation. As an example, see the discussion in Item 7. MD&A. of the Utility's unrecovered pipeline-related costs incurred since the San Bruno accident.

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. 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 rely on evolving information and operational technology systems and network infrastructures that are becoming more complex as new technologies and systems are implemented to modernize capabilities to safely and reliably deliver gas and electric services. The Utility's ability to serve its customers requires the continued operation of complex information technology systems and network infrastructure that are interconnected with the systems and 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, many of which are highly complex. 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 information and operational systems and networks due to a physical attack, cyber-attack or other cause 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 effectiveness of the Utility's control environment, and/or the Utility's ability to timely file required regulatory reports.

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, the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. The operation of the nuclear facilities also depends on the availability of adequate fuel supplies. 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 14 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 and that future changes in legislation, regulations, orders, or their interpretation, could result in the Utility ceasing operations at Diablo Canyon before the licenses expire. 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 it 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.

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.

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, and may be, 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 14 to 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, reduced precipitation, 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 lower 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. Should the Utility increase 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. 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 assets that are located on levees throughout the Utility's service territory. 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. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under “Electric Utility Operations” and “Natural Gas Utility Operations.” The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11.2 million square feet of real property, including 8.8 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

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

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. In 2002 the Utility agreed to permanently preserve six “beneficial public values” on all its watershed lands through conservation easements or equivalent protections, and to make up to 44,000 acres of its watershed lands available for donation to public entities or qualified non-profit conservation organizations. The six “beneficial public values” being preserved through these conservation easements include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Pacific Forest Watershed Lands Stewardship Council oversees the implementation of a land conservation plan that articulates the long-term management objectives for these watershed lands. The Utility’s goal is to implement all the transactions needed to implement the land conservation plan by the end of 2017, 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 14 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

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.

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.

CPUC Investigations Regarding the Utility’s Gas Transmission System and the San Bruno Accident

There are three CPUC investigative enforcement proceedings pending against the Utility. These investigations relate to (1) the Utility’s safety recordkeeping 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, recordkeeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the San Bruno accident.

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in these investigations in which they determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision calling for total penalties of $1.4 billion on the Utility to address all violations, allocated as follows: (1) $950 million fine to be paid to the State General Fund, (2) $400 million refund to ratepayers of previously authorized revenues, and (3) remedial measures that the ALJs estimate will cost the Utility at least $50 million. The presiding officer decisions are not the final decisions of the CPUC. Three of the five CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. In addition, in October 2014, the Utility and other parties, including the SED, TURN, the ORA, the City and County of San Francisco, and the City of San Bruno appealed the presiding officer decisions.

In its appeals, the Utility argued that the penalties imposed and the findings and conclusions on which they are based do not meet applicable legal standards, are based on the misapplication of California law and regulations, and are unconstitutional. The Utility has asked the CPUC to order the Utility to pay a significantly reduced penalty that is reasonable and proportionate in light of the nature of the violations and that takes into account the substantial unrecovered amounts the Utility has already spent and forecasts that it will spend on gas system safety. The Utility requested that it be allowed 180 days to raise the funds it may be ordered to pay to the State General Fund rather than the 40 days specified in the decision. The Utility also argued that the entire penalty should go toward funding investments in the Utility's gas transmission system. TURN, the ORA, and the City and County of San Francisco jointly filed an appeal urging the CPUC to disallow the Utility's recovery of remaining PSEP costs of $877 million and to require the Utility to pay $473 million to the State General Fund. These parties also argue that the record in the investigative proceedings would support an even larger penalty than stated in the decision. The City of San Bruno appealed the rejection of its proposals for the appointment of an independent monitor to oversee the Utility's natural gas operations and for the establishment of a pipeline safety trust. It is uncertain when the final outcome of the investigations will be determined.

While the various appeals and requests for review of the presiding officer decisions are unresolved there continues to be significant uncertainty about the ultimate forms and amounts of penalties (including fines) that will be imposed on the Utility. The impact on PG&E Corporation's and the Utility's Consolidated Financial Statements will depend on the amounts and forms of penalties that are ultimately adopted by the CPUC. For more information, see discussions "Enforcement and Litigation Matters" in Item 7. MD&A and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in Item 8.

Federal Criminal Indictment

On July 29, 2014, a federal grand jury in the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts (increased from 12 counts charged in the original indictment) 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. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges an alternative fine under the Alternative Fines Act which 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." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate 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. A status conference is scheduled to be held in court on March 9, 2015. 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

At December 31, 2014, there were also five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court in November 2013, which has been amended to add a fourth shareholder plaintiff and to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint for the limited purpose of allowing briefing and hearing on demurrers (state court motions to dismiss). On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the defendant directors and officers and (2) have not adequately pled why such demand should be excused. The court has since clarified that the appropriate board on whom the plaintiffs should have demanded with respect to the claims in the operative complaint is the 2013 PG&E Corporation Board of Directors (and the 2014 Board regarding the allegations first raised in plaintiffs' 2014 amended consolidated complaint). The Court has invited plaintiffs to amend their complaint to accommodate this clarification, and defendants to refile a demurrer on this amended complaint if they so choose. Accordingly, briefing and litigation on this motion is expected to continue through the first quarter of 2015. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. A fifth purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The following individuals serve as executive officers (1) of PG&E Corporation and/or the Utility, as of February 10, 2015. 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.	65	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
		Chairman of the Board and Chief Executive Officer, DTE Energy Company	August 1998 to September 30, 2010
Christopher P. Johns	54	President	August 1, 2009 to present
		Senior Vice President, Financial Services	May 1, 2009 to July 31, 2009
		Senior Vice President and Chief Financial Officer, PG&E Corporation	May 1, 2009 to July 31, 2009
Nickolas Stavropoulos	56	Executive Vice President, Gas Operations	June 13, 2011 to present
		Executive Vice President and Chief Operating Officer, U.S. Gas Distribution, National Grid	August 2007 to March 31, 2011
Geisha J. Williams	53	Executive Vice President, Electric Operations	June 1, 2011 to present
		Senior Vice President, Energy Delivery	December 1, 2007 to May 31, 2011
Karen A. Austin	53	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	52	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
Helen A. Burt	58	Senior Vice President, Corporate Affairs	September 18, 2014 to present
		Senior Vice President, Corporate Affairs, PG&E Corporation	September 18, 2014 to present
		Senior Vice President and Chief Customer Officer	February 27, 2006 to September 17, 2014

Loraine M. Giammona		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	53	Senior Vice President and Chief Nuclear Officer	April 2, 2012 to present
		President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company	December 2009 to March 2012
Kent M. Harvey	56	Senior Vice President and Chief Financial Officer, PG&E Corporation	August 1, 2009 to present
		Senior Vice President, Financial Services	August 1, 2009 to present

Gregory K. Kiraly	50	Senior Vice President, Electric Distribution Operations	September 18, 2012 to present
		Vice President, Electric Distribution Operations	October 1, 2011 to September 17, 2012
		Vice President, SmartMeter Operations	August 23, 2010 to September 30, 2011
		Vice President, Electric Maintenance and Construction	January 1, 2010 to August 22, 2010
Steven E. Malnight	42	Senior Vice President, Regulatory Affairs	September 18, 2014 to present
		Vice President, Customer Energy Solutions	May 15, 2011 to September 17, 2014
		Vice President, Integrated Demand Side Management	July 1, 2010 to May 14, 2011
		Vice President, Renewable Energy	May 1, 2009 to June 30, 2010
Hyun Park	53	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
John R. Simon	50	Senior Vice President, Human Resources	April 16, 2007 to present
		Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to present
Jesus Soto, Jr.	47	Senior Vice President, Engineering, Construction and Operations	September 16, 2013 to present
		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	53	Senior Vice President, Energy Procurement	October 1, 2008 to present
Dinyar B. Mistry	53	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
		Vice President and Chief Risk and Audit Officer	September 16, 2009 to March 7, 2010
		Vice President and Chief Risk and Audit Officer, PG&E Corporation	August 1, 2009 to March 7, 2010

(1) Mr. Earley, Mr. Johns, Ms. Burt, Mr. Harvey, Mr. Park, and Mr. Simon are executive officers of both PG&E Corporation and the Utility. All other listed officers are executive officers of the Utility only.

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PART II

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

As of January 27, 2015, there were 61,989 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 on page 125 of this report within "Quarterly Consolidated Financial Data (Unaudited)"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: Common Stock and Share-Based Compensation−Dividends in Item 8 and in "Liquidity and Financial Resources – Dividends" in Item 7. MD&A.

Sales of Unregistered Equity Securities

PG&E Corporation did not make any equity contributions to the Utility during the quarter ended December 31, 2014. The Utility was in compliance with the 52% common equity component of its capital structure authorized by the CPUC and had adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2014.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2014, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2014, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2014	2013	2012	2011	2010
PG&E Corporation					
For the Year					
Operating revenues	$17,090	$15,598	$15,040	$14,956	$13,841
Operating income	2,450	1,762	1,693	1,942	2,308
Income from continuing operations	1,450	828	830	858	1,113
Earnings per common share from continuing operations, basic (1)	3.07	1.83	1.92	2.10	2.86
Earnings per common share from continuing operations, diluted	3.06	1.83	1.92	2.10	2.82
Dividends declared per common share (2)	1.82	1.82	1.82	1.82	1.82
At Year-End					
Common stock price per share	$53.24	$40.28	$40.18	$41.22	$47.84
Total assets	60,127	55,605	52,449	49,750	46,025
Long-term debt (excluding current portion)	15,050	12,717	12,517	11,766	10,906
Capital lease obligations (excluding current portion) (3)	69	90	113	212	248
Energy recovery bonds (excluding current portion) (4)	-	-	-	-	423
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$17,088	$15,593	$15,035	$14,951	$13,840
Operating income	2,452	1,790	1,695	1,944	2,314
Income available for common stock	1,419	852	797	831	1,107
At Year-End					
Total assets	59,865	55,049	51,923	49,242	45,679
Long-term debt (excluding current portion)	14,700	12,717	12,167	11,417	10,557
Capital lease obligations (excluding current portion) (3)	69	90	113	212	248
Energy recovery bonds (excluding current portion) (4)	-	-	-	-	423

(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.

(4) The energy recovery bonds matured in December 2012.

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

OVERVIEW

Pacific Gas and Electric Company generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E Corporation is the parent holding company of the Utility. The authorized revenue requirements set by the CPUC in the GRC and GT&S rate cases and by the FERC in TO rate cases provide the Utility an opportunity to earn its authorized rates of return on its "rate base" – the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers. Other than its electric transmission and certain GT&S revenues, the Utility's decoupling of base revenues and sales volume eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand.

The Utility's revenue requirements are set based on forecast costs. Differences between forecast costs and actual costs can occur for numerous reasons, including the volume of new customer connections, the detection and mitigation of emerging safety threats, 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 additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to 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.

There may be some types of costs that the CPUC has determined will not be recoverable through rates or for which the Utility does not seek recovery, such as certain pipeline-related costs and fines associated with the Utility's natural gas transmission system. The CPUC could also disallow recovery of costs that it finds were not prudently or reasonably incurred. The timing and amount of the unrecoverable or disallowed costs can materially impact the Utility's net income, as described more fully below.

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

PG&E Corporation's financial results for 2014 reflect an increase in the Utility's revenues as authorized in the CPUC's final decision issued in the Utility's 2014 GRC on August 14, 2014. (See "Results of Operations" below.)

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 for the year ended December 31, 2014 compared to the prior year (see "Results of Operations" below for additional information):

(in millions, except per share amounts)	Earnings	EPS (diluted)
Income Available for Common Shareholders - 2013	$814	$1.83
Natural gas matters (1)	176	0.43
2014 GRC expense recovery(2)	134	0.29
Tax benefit - repairs method and forecast change (3)	115	0.24
Growth in rate base earnings (4)	101	0.21
Gain on disposition of SolarCity stock	27	0.06
Regulatory matters (5)	20	0.04
Gas transmission revenues	8	0.02
Uneconomic project and lease termination	8	0.02
Increase in shares outstanding (6)	-	(0.15)
Other	33	0.07
Income Available for Common Shareholders - 2014	$1,436	$3.06

(1) Represents the decrease in net costs related to natural gas matters during 2014 as compared to 2013. These amounts are not recoverable through rates. See "Results of Operations - Operating and Maintenance" below.
(2) In 2013, the Utility incurred approximately $200 million of expense and $1 billion of capital costs above authorized levels. The 2014 GRC decision authorized revenues that support this higher level of spending in 2014 and throughout the GRC period. The amounts in the table represent the after-tax higher authorized revenue recognized during 2014, for the recovery of these expenses and costs.
(3) Represents the favorable impact of recent IRS guidance and forecast changes based on flow-through ratemaking treatment for federal tax deductions resulting from temporary differences attributable to the accelerated recognition of repairs and certain other property-related costs, as reflected in the revenue requirements authorized in the 2014 GRC decision. See "Income Tax Provision" below.
(4) Represents the impact of the increase in rate base as authorized in various rate cases, including the 2014 GRC, during 2014 as compared to 2013.
(5) Includes customer energy efficiency incentive awards.
(6) Represents the impact of a higher number of weighted average shares of common stock outstanding during 2014 as compared to 2013. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including unrecovered expenses.

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 Pending Investigations and Enforcement Matters. The assigned CPUC ALJs overseeing the three pending investigations regarding the Utility's gas transmission system and the San Bruno accident have issued decisions to impose total fines and disallowances of $1.4 billion on the Utility. The Utility and other parties have appealed the decisions and several Commissioners have requested reviews of the decisions. It is uncertain when the final outcome of these investigations will be determined. At December 31, 2014, the Consolidated Balance Sheets included an accrual of $200 million for the minimum amount of fines deemed probable. There is also a pending federal criminal indictment against the Utility alleging that the Utility knowingly and willfully violated the Pipeline Safety Act and illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. Based on the superseding indictment's allegations, the maximum statutory fine would be $14 million and the maximum alternative fine would be approximately $1.13 billion. Federal and state authorities also are conducting investigations in connection with certain communications between the Utility and CPUC personnel. Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to these and other enforcement matters. (See "Enforcement and Litigation Matters" below.)

- The Timing and Outcome of Ratemaking Proceedings. In the GT&S rate case the Utility has requested that the CPUC authorize revenue requirements for the Utility's gas transmission and storage operations from 2015 through 2017. The Utility has requested an increase in its 2015 revenue requirements of $555 million over the comparable authorized revenues, as well as increases for 2016 and 2017. In response to Utility's violations of the CPUC's rules regarding ex parte communications relating to the 2015 GT&S rate case, the CPUC issued a decision to disallow some GT&S incremental revenues that may otherwise be authorized in the final decision which is scheduled to be issued in August 2015. The Utility and other parties have filed applications requesting the CPUC to reconsider this decision. It is uncertain whether this decision will be upheld and what amount of revenue requirements will ultimately be authorized in the final GT&S rate case decision. It is also uncertain whether the final outcome of the pending CPUC investigations will affect the outcome of the 2015 GT&S rate case. In addition, the Utility has a TO rate case pending at the FERC. (See "Ratemaking and Other Regulatory Proceedings" 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 discussed in Item 1A. Risk Factors.

- The Ability of the Utility to Control Operating Costs and Capital Expenditures. PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows could be materially affected if the Utility's actual costs differ from the amounts authorized in the final 2014 GRC decision and future rate case decisions. During the quarter ended December 31, 2014, the Utility recorded a charge of $116 million for the increase in the Utility's forecast of PSEP capital expenditures that are expected to exceed authorized amounts. The Utility could incur additional charges in the future if the forecast of PSEP-related capital expenditures increases. The Utility also forecasts that in 2015 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million, including costs to perform continuing work under the Utility's PSEP and other gas transmission safety work, as well as legal and other expenses. Actual costs could be higher. The final outcome of the pending CPUC investigations and the CPUC enforcement actions with respect to the Utility's violations of the ex parte communication rules also could affect the ultimate amount of unrecovered costs.

- 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 2014, PG&E Corporation issued $802 million of common stock and made equity contributions to the Utility of $705 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity to support the Utility's capital expenditures and to fund unrecovered pipeline-related costs. PG&E Corporation expects that it will issue additional common stock to fund its equity contributions to enable the Utility to pay fines and compliance costs as may be required by the final outcomes of the CPUC investigations, the criminal proceeding, and the other enforcements matters. These additional issuances could have a material dilutive effect 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" below, 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 2014 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "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 2014, 2013, and 2012. 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)	2014	2013	2012
Consolidated Total	$1,436	$814	$816
PG&E Corporation	17	(38)	19
Utility	$1,419	$852	$797

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. In 2014, PG&E Corporation's operating results increased reflecting $45 million of realized gains and associated tax benefits recognized in connection with an equity investment in SolarCity. PG&E Corporation's operating results in 2013 reflected an impairment loss of $28 million on its tax equity fund investments and higher charitable contributions as compared to 2012.

Utility

The table below shows certain items from the Utility's Consolidated Statements of Income for 2014, 2013 and 2012. 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 onrate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

The Utility’s operating results for 2014 reflect the increase in authorized revenues effective January 1, 2014 that was approved by the CPUC in the 2014 GRC decision issued on August 14, 2014. (See “Utility Revenues and Costs that Impacted Earnings” below.)

	2014			2013			2012		
	Revenues and Costs:			Revenues and Costs:			Revenues and Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 7,059	$ 6,597	$ 13,656	$ 6,465	$ 6,024	$ 12,489	$ 6,414	$ 5,600	$ 12,014
Natural gas operating revenues	2,072	1,360	3,432	1,776	1,328	3,104	1,772	1,249	3,021
Total operating revenues	9,131	7,957	17,088	8,241	7,352	15,593	8,186	6,849	15,035
Cost of electricity	-	5,615	5,615	-	5,016	5,016	-	4,162	4,162
Cost of natural gas	-	954	954	-	968	968	-	861	861
Operating and maintenance	4,247	1,388	5,635	4,374	1,368	5,742	4,563	1,482	6,045
Depreciation, amortization, and decommissioning	2,432	-	2,432	2,077	-	2,077	1,928	344	2,272
Total operating expenses	6,679	7,957	14,636	6,451	7,352	13,803	6,491	6,849	13,340
Operating income	2,452	-	2,452	1,790	-	1,790	1,695	-	1,695
Interest income (1)			8			8			6
Interest expense (1)			(720)			(690)			(680)
Other income, net (1)			77			84			88
Income before income taxes			1,817			1,192			1,109
Income tax provision (1)			384			326			298
Net income			1,433			866			811
Preferred stock dividend requirement (1)			14			14			14
Income Available for Common Stock			$ 1,419			$ 852			$ 797

(1) These items impacted earnings.

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Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2014, 2013 and 2012, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased $890 million or 11% in 2014 compared to 2013. This amount includes 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 in 2012 for spent nuclear fuel storage costs. (See "Ratemaking and Other Regulatory Proceedings" below.) The total increase in operating revenues also includes approximately $150 million, consisting of revenues authorized by the CPUC for recovery of nuclear decommissioning costs and certain PSEP-related costs and revenues authorized by the FERC in the TO rate case. The Utility also collected higher gas transmission revenues driven by increased demand for gas-fired generation.

The Utility's electric and natural gas operating revenues increased $55 million or 1% in 2013 compared to 2012, primarily due to an increase of $294 million as authorized in various rate cases, partially offset by a decrease in revenues of $196 million as a result of the lower ROE authorized by the CPUC in the 2013 Cost of Capital proceeding.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings decreased $127 million or 3% in 2014 compared to 2013 and $189 million or 4% in 2013 compared to 2012, primarily due to lower net costs incurred in connection with natural gas matters shown in the table below. These decreases were offset by higher benefit-related expenses and other operating expenses of $120 million in 2014 as compared to 2013 and $53 million in 2013 as compared to 2012. Additionally, the Utility incurred an $88 million charge in 2012 for an increase in estimated environmental remediation costs associated with the Hinkley natural gas compressor station site, with no comparable charge taken in 2013.

The following table provides a summary of the Utility's costs associated with natural gas matters that are not recoverable through rates:

(in millions)	2014	2013	2012	Cumulative December 31, 2014
Pipeline-related expenses (1)	$347	$387	$477	$1,757
Disallowed capital expenditures (2)	116	196	353	665
Accrued fines (3)	12	22	17	251
Third-party liability claims (4)	(7)	110	80	558
Insurance recoveries (5)	(112)	(70)	(185)	(466)
Contribution to City of San Bruno	-	-	70	70
Total natural gas matters	$356	$645	$812	$2,835

(1) In 2014, the Utility incurred $149 million of PSEP-related expenses, $155 million of other gas safety-related work, and $43 million of legal and other expenses. From December 31, 2010 through December 31, 2014, the Utility incurred respective expenses of $885 million, $502 million, and $370 million. See "Enforcement and Litigation Matters" below.
(2) Amounts represent charges for PSEP capital costs expected to exceed the authorized amount. See "Pipeline Safety Enhancement Plan" in Note 14 of the Consolidated Financial Statements in Item 8.

(3) Includes fines related to ex parte communications, the Carmel incident, and other fines. See "Pending CPUC Investigations" below. The Utility has paid $40 million of fines through December 31, 2014.
(4) Amounts represent third-party liability claims and associated legal costs. The Utility's liability for third-party claims related to the San Bruno accident was reduced in 2014 to reflect the settlement of all outstanding third-party claims. Since the San Bruno accident, the Utility has made cumulative settlement payments of $532 million through December 31, 2014.
(5) The Utility has recognized insurance recoveries for third-party claims and associated legal costs. The Utility has been engaged in settlement negotiations with its insurers regarding recovery of its remaining claims and costs.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased $355 million or 17% in 2014 compared to 2013 and $149 million or 8% in 2013 compared to 2012. 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, and during 2013 as compared to 2012.

Interest Income, Interest Expense, and Other Income, Net

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

Income Tax Provision

The Utility's revenue requirements for 2014 through 2016, as authorized in the 2014 GRC decision, reflect 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 2014 are lower as compared to 2013, and are expected to remain lower in 2015 and 2016 due to these temporary differences that are now being flowed through. PG&E Corporation and the Utility's 2014 financial results reflect a reduction in income tax expense associated with these temporary differences. (See Note 8 of the Notes to the Consolidated Financial Statements in Item 8.)

The Tax Increase Prevention Act, signed into law on December 19, 2014, extended 50% bonus federal tax depreciation on qualified property placed into service in 2014. The Utility's earnings were not impacted by the incremental tax depreciation as the flow-through ratemaking discussed above does not apply and the 2014 GRC decision requires the Utility to refund to customers the estimated cost of service benefits associated with this tax law change.

The Utility's income tax provision increased $58 million or 18% in 2014 as compared to 2013 and $28 million or 9% in 2013 as compared to 2012. The increase in the tax provision was primarily due to higher pre-tax income, 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:

	2014		2013		2012	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit) (1)	1.6		(2.2	)	(3.0	)
Effect of regulatory treatment of fixed asset differences (2)	(14.7	)	(3.8	)	(3.9	)
Tax credits	(0.7	)	(0.4	)	(0.6	)
Benefit of loss carryback	(0.8	)	(1.0	)	(0.4	)
Non deductible penalties	0.3		0.7		0.5	
Other, net	0.4		(0.9	)	(0.8	)
Effective tax rate	21.1	%	27.4	%	26.8	%

(1) Includes the effect of state flow-through ratemaking treatment.
(2) Represents effect of federal flow-through ratemaking treatment including those deductions related to repairs and certain other property-related costs discussed above.

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Utility Revenues and Costs that did not Impact Earnings

Cost of Electricity

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, 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 volume of power purchased by the Utility is driven by customer demand, the availability of the Utility's own generation facilities (including hydroelectric generations), and the cost effectiveness of each source of electricity. Additionally, the cost of electricity is impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with California law.

(in millions)	2014	2013	2012
Cost of purchased power	$5,266	$4,696	$3,873
Fuel used in own generation facilities	349	320	289
Total cost of electricity	$5,615	$5,016	$4,162
Average cost of purchased power per kWh	$0.101	$0.094	$0.079
Total purchased power (in millions of kWh)	52,008	49,941	48,933

Cost of Gas

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas, 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, changes in customer demand, and by costs associated with complying with California's GHG laws.

(in millions)	2014	2013	2012
Cost of natural gas sold	$813	$807	$676
Transportation cost of natural gas sold	141	161	185
Total cost of natural gas	$954	$968	$861
Average cost per Mcf of natural gas sold	$4.37	$3.54	$2.91
Total natural gas sold (in millions of Mcf) (1)	186	228	232

(1) One thousand cubic feet

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings. For 2014, 2013 and 2012, 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 debt and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect related to its debt 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's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters, fines imposed in connection with the pending CPUC investigations and other matters described in "Enforcement and Litigation Matters" below, and certain environmental remediation costs. 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, the majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions. (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. During 2014, PG&E Corporation sold 11 million shares of common stock for cash proceeds of $496 million, net of commissions of $4 million, under an equity distribution agreement. There were no sales during the fourth quarter of 2014. In addition, during 2014, PG&E Corporation sold 8 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 $306 million.

The proceeds from these equity issuances were used for general corporate purposes, including the contribution of equity into the Utility. For the year ended December 31, 2014, PG&E Corporation made equity contributions to the Utility of $705 million to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC. These equity issuances have been dilutive to PG&E Corporation's EPS to the extent that the proceeds were used by the Utility to restore equity that has been reduced by unrecoverable costs and charges.

PG&E Corporation forecasts that it will issue additional common stock to fund the Utility's equity needs. PG&E Corporation forecasts that it will issue between $400 million and $600 million in common stock during 2015, excluding amounts attributable to fines the Utility may be required to pay in connection with final outcomes of the CPUC investigations, the criminal proceeding, and other enforcements matters. Future issuances of common stock by PG&E Corporation to fund equity contributions could continue to have a material dilutive effect on EPS depending upon the ultimate outcomes of the matters described in "Enforcement and Litigation Matters" below and the outcome of the GT&S rate case as described in “Ratemaking and Other Regulatory Proceedings” below.

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 Note 12 of the Notes to the Consolidated Financial Statements in Item 8.)

Revolving Credit Facilities and Commercial Paper Programs

At December 31, 2014, PG&E Corporation and the Utility had $300 million and $2.6 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. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, these revolving credit facilities include usual and customary provisions regarding events of default and covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. At December 31, 2014, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

2014 Debt Financings

PG&E Corporation and the Utility issued $2.3 billion in long-term debt and $300 million in short-term debt during the year ended December 31, 2014. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

Dividends

The Board of Directors of PG&E Corporation and the Utility have authority to declare dividends on their respective common stock. Dividends are not payable unless and until declared by the applicable Board of Directors. The CPUC requires that the Utility maintain, on average, its authorized capital structure including a 52% equity component and that the PG&E Corporation 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. Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change their view as to the prudent level of cash conservation.

The Board of Directors of PG&E Corporation declared and paid common stock dividends of $0.455 per share for each of the quarters in 2014, 2013, and 2012, for annual dividends of $1.82 per share. The Utility's Board of Directors declared and paid common stock dividends in the aggregate amount of $179 million to PG&E Corporation for each of the quarters in 2014, 2013, and 2012. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may pay any common stock dividends.

The following table summarizes PG&E Corporation's and the Utility's dividends paid:

(in millions)	2014	2013	2012
PG&E Corporation:			
Common stock dividends paid	$802	$782	$746
Common stock dividends reinvested in Dividend Reinvestment			

and Stock Purchase Plan	21	22	22
Utility:			
Common stock dividends paid	$716	$716	$716
Preferred stock dividends paid	14	14	14

Additionally, in December 2014, the following dividends were declared:

· the Board of Directors of PG&E Corporation declared quarterly common stock dividends of $0.455 per share, totaling $217 million, of which approximately $211 million was paid in January 2015 to shareholders of record on December 31, 2014;

· the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable in February 2015, to shareholders of record on January 30, 2015.

Subject to the outcome of the matters described in "Enforcement and Litigation Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend. (See Item 1A. Risk Factors.)

PG&E Corporation

PG&E Corporation affiliates previously entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that were considered VIEs. On July 2, 2014, PG&E Corporation disposed of its interest in the tax equity agreements for $87 million and has no remaining commitment to fund these agreements. Sales proceeds, lease payments, investment contributions, benefits, and customer payments received were included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows to coincide with the applicable lease structure.

Utility

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.

The Utility's cash flows from operating activities for 2014, 2013, and 2012 were as follows:

(in millions)	2014	2013	2012
Net income	$1,433	$866	$811
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,432	2,077	2,272
Allowance for equity funds used during construction	(100)	(101)	(107)
Deferred income taxes and tax credits, net	731	1,103	684
PSEP disallowed capital expenditures	116	196	353
Other	226	299	236
Effect of changes in operating assets and liabilities:	(1,219)	(1,024)	679
Net cash provided by operating activities	$3,619	$3,416	$4,928

During 2014, net cash provided by operating activities increased by $203 million as compared to 2013. This increase was primarily due to $500 million in net tax refunds received during 2014 as compared to $62 million in net tax payments made during 2013, $160 million in additional GHG auction proceeds during 2014 as compared to 2013, and $137 million in additional collateral returned to the Utility in 2014 as compared to 2013. The increase was offset by higher purchased power costs of $599 million (see "Cost of Electricity" within "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above) and various fluctuations in other cash flows.

During 2013, net cash provided by operating activities decreased by $1.5 billion as compared to 2012 when the Utility collected $460 million from customers related to the energy recovery bonds which matured at the end of 2012. In addition, in 2013, the amount of cash collateral returned to the Utility by third parties was $243 million lower than in 2012, the payments the Utility received under the DOE settlement for reimbursement of the Utility's spent nuclear fuel disposal costs was $221 million lower, net of legal fees, than the Utility received in 2012, and the Utility's tax payments were $236 million higher than in 2012. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

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

- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of fines or penalties that will be imposed in connection with the pending investigations and other enforcement matters, as well as any costs associated with remedial actions the Utility may be required to implement (see "Enforcement and Litigation Matters" below);
- the timing and amount of pipeline-related costs the Utility incurs, but does not recover, associated with its natural gas system (see "Operating and Maintenance" within "Results of Operations – Utility Revenues and Costs that Impacted Earnings" above);
- the volatility in energy commodity costs and seasonal load;
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments; and
- the timing of the resolution of the Chapter 11 disputed claims and the related refunds passed through to customers (see Note 12 of the Notes to the Consolidated Financial Statements in Item 8).

Investing Activities

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. The amount and timing of the Utility's capital expenditures is affected by many factors such as the approvals of the CPUC, FERC, and other regulatory agencies, the volume of new customer connections, and the occurrence of storms that cause outages or damages to the Utility's infrastructure. The funds in the nuclear decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for 2014, 2013, and 2012 were as follows:

(in millions)	2014	2013	2012
Capital expenditures	$(4,833)	$(5,207)	$(4,624)
Decrease in restricted cash	3	29	50
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,336	1,619	1,133
Purchases of nuclear decommissioning trust investments	(1,334)	(1,604)	(1,189)
Other	29	21	16
Net cash used in investing activities	$(4,799)	$(5,142)	$(4,614)

Net cash used in investing activities decreased by $343 million in 2014 compared to 2013 due to 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.

Net cash used in investing activities increased by $528 million in 2013 compared to 2012 due to an increase of $583 million in capital expenditures, partially offset by net proceeds associated with sales of nuclear decommissioning trust investments in 2013 as compared to net purchases of nuclear decommissioning trust investments in 2012.

Future cash flows used in investing activities primarily depend on the timing and amount of capital expenditures. The Utility forecasts that it will incur $5.5 billion in capital expenditures in 2015 and between $5.3 billion and $5.8 billion in 2016. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases.

Financing Activities

The Utility's financing activities are impacted by the conditions in the capital markets and the maturity date of existing debt instruments. The Utility forecasts that its financing needs will increase as it incurs non-recoverable pipeline-related costs and fines associated with the pending investigations and other enforcement matters.

The Utility's cash flows from financing activities for 2014, 2013, and 2012 were as follows:

(in millions)	2014	2013	2012
Net issuances (repayments) of commercial paper, net of discount	$(583)	$542	$(1,021)
Proceeds from issuance of short-term debt, net of issuance costs	300	-	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs	1,961	1,532	1,137
Short-term debt matured	-	-	(250)
Repayments of long-term debt	(539)	(861)	(50)
Energy recovery bonds matured	-	-	(423)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution from PG&E Corporation	705	1,140	885
Other	56	(26)	28
Net cash provided by (used in) financing activities	$1,170	$1,597	$(424)

In 2014, net cash provided by financing activities decreased by $427 million compared to the same period in 2013. In 2013, net cash provided by financing activities increased by $2.0 billion compared to 2012. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depends on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2014:

	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):	$714	$2,304	$2,870	$21,779	$27,667
Purchase obligations (2):					
Power purchase agreements:	3,566	6,839	6,239	33,896	50,540
Natural gas supply, transportation, and storage	544	271	214	648	1,677
Nuclear fuel agreements	138	260	224	429	1,051
Pension and other benefits (3)	388	776	776	388	2,328
Operating leases (2)	44	76	57	183	360
Preferred dividends (4)	14	28	28	-	70
PG&E Corporation					
Long-term debt (1):	8	16	359	-	383
Total Contractual Commitments	$5,416	$10,570	$10,767	$57,323	$84,076

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2014 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 Note 14 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 14 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements) in Item 8.

ENFORCEMENT AND LITIGATION MATTERS

Since the San Bruno accident occurred on September 9, 2010, PG&E Corporation and the Utility have incurred total cumulative charges of approximately $2.8 billion related to natural gas matters that are not recoverable through rates. See "Results of Operations" above.

Pending CPUC Investigations

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility related to the Utility's natural gas transmission operations and practices and the San Bruno accident. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision calling for total fines and disallowances of $1.4 billion on the Utility to address all violations, allocated as shown in the table below. The ALJs' decisions are not the final decisions of the CPUC. Three CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. In addition, the Utility and other parties, including the SED, TURN, the ORA, the City and County of San Francisco, and the City of San Bruno have appealed the presiding officer decisions. (For additional information, see Note 14 of the Notes to the Consolidated Financial Statements in Item 8.) It is uncertain when the final outcome of the investigations will be determined.

While the various appeals and requests for review of the presiding officer decisions are unresolved there continues to be significant uncertainty about the ultimate forms and amounts of penalties (including fines) that will be imposed on the Utility. At December 31, 2014, the Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable. The impact on PG&E Corporation's and the Utility's Consolidated Financial Statements will depend on the amounts and forms of penalties that are ultimately adopted by the CPUC. Fines payable to the State General Fund or refunds of revenues would be charged to net income when it is probable that such fines or refunds will be imposed and the amounts can be reasonably estimated. A disallowance of previously authorized and incurred capital costs would be charged to net income when the disallowance is probable and the amount can be reasonably estimated. Penalties in the form of future disallowed costs would be charged to net income in the period during which the actual costs are incurred. Although PG&E Corporation and the Utility believe it is probable that the CPUC will impose total penalties materially in excess of the $200 million previously accrued, they are unable to make a better estimate due to the variety of potential combinations of amounts and forms of penalties that could ultimately be imposed on the Utility and uncertainty about the timing of recognition. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows.

If the presiding officer joint decision becomes final, the Utility estimates that its total pre-tax unrecovered costs and fines related to natural gas transmission operations would be about $4.85 billion based on current forecasts, allocated as follows:

Description of Component:	Amounts (in millions)
Fine payable to the State General Fund	$950
Refund of revenues previously authorized	400
Additional estimated unrecoverable costs (1)	50
Total penalty	1,400
PSEP costs previously disallowed	635
Total penalty and PSEP cost disallowance	2,035
Gas pipeline safety costs incurred or committed (2)	2,800

Less: Credit for PSEP costs previously disallowed	(635)
Total estimated shareholder impact before non-deductibility of fines	4,200
Estimated impact of non-deductibility of fines for tax purposes (3)	650
Total estimated shareholder impact (pre-tax)	$4,850

(1) The presiding officer joint decision estimates that the Utility would incur at least $50 million to implement remedial measures. Actual costs could differ materially based on the scope and timing of work. In addition, the decision requires shareholders to reimburse intervenors for legal and litigation expenses.
(2) Actual and forecast costs for gas pipeline safety work in 2010 and beyond that will not be recovered through rates, including previously disallowed PSEP capital and expense. This amount includes charges of $665 million, including an additional charge of $116 million recorded during the three months ended December 31, 2014, for PSEP capital costs that are forecasted to exceed the authorized amounts.
(3) Estimated impact calculated based on the Utility's statutory tax rate.

Federal Criminal Indictment

On July 29, 2014, a federal grand jury in the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been returned on April 1, 2014. The superseding indictment charges 27 felony counts (increased from 12 counts charged in the original indictment) 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. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges an alternative fine under the Alternative Fines Act which 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." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternate 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. A status conference is scheduled to be held in court on March 9, 2015. 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.

Other Enforcement Matters

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

Improper CPUC Communications

On September 15, 2014, the Utility notified the CPUC and the ALJ overseeing the 2015 GT&S rate case that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. (The Utility discovered the communications as part of an internal review of communications between the Utility and the CPUC undertaken after the City of San Bruno filed a motion at the CPUC in late July 2014 alleging that various email communications between the Utility's employees and CPUC personnel violated the ex parte communication rules with respect to the pending CPUC investigative enforcement proceedings against the Utility. The Utility believes that the communications cited by San Bruno in its July 2014 motion are not prohibited ex parte communications. The CPUC has not yet addressed San Bruno's motion and its request that the CPUC penalize the Utility.)

On November 20, 2014, the CPUC issued a decision imposing a fine of $1.05 million on the Utility and disallowing up to the entire amount of the revenue increase that would have been collected from ratepayers over the five-month period between March 2015 and August 2015. The exact amount of the revenue disallowance will be determined in the CPUC's final decision in the GT&S rate case expected to be issued in August 2015. In addition, the decision prohibits the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors in any rate-setting or adjudicatory proceeding and requires the Utility to report communications with senior CPUC staff, in any rate-setting proceeding or adjudicatory proceeding before the CPUC, for one year from the effective date of the decision. With respect to the GT&S rate case, the ban will be in effect until the resolution of the GT&S rate case or one year from the effective date of the decision, whichever is later. The Utility and other parties have requested that the CPUC reconsider its decision. The ORA, TURN, and the City of San Bruno argue that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million. It is uncertain when the CPUC will address these applications for rehearing. (See "Ratemaking and Other Regulatory Proceedings" below.)

In October and December 2014, the Utility notified the CPUC of additional email communications between the Utility and CPUC personnel regarding various matters (not limited to the GT&S rate case), that the Utility believes may constitute or describe ex parte communications. As of January 30, 2015, the Utility had provided copies of approximately 65,000 email communications between the CPUC and the Utility to the CPUC and the City of San Bruno. It is uncertain whether any of these email communications will be challenged as prohibited ex parte communications or as improper or illegal.

The Utility believes it is probable that CPUC enforcement actions will be taken in connection with these additional ex parte communications but is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties. It is also possible that other parties may request that the CPUC rescind decisions or take other action in open or closed proceedings to address ex parte communications that they may allege occurred regarding substantive issues in those proceedings. For example, TURN and the ORA have filed petitions to request that the CPUC rescind a $29 million shareholder incentive awarded to the Utility in 2010 for the successful implementation of the Utility's 2006-2008 energy efficiency programs based on their allegation that prohibited ex parte communications tainted the decision. It is uncertain whether the CPUC will grant these petitions or whether parties will request the CPUC to take action in other proceedings. It is also uncertain whether the ex parte communication issues will affect the outcome of other pending legal matters, ratemaking or regulatory proceedings, investigations and enforcement matters.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office have begun investigations in connection with these communications. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility.

Gas Safety Citation Program

The SED, the division of the CPUC primarily responsible for overseeing the safety of electric and natural gas utility operations in California, conducts periodic audits of the Utility's operating practices and investigates potential violations. In December 2011, the CPUC adopted a gas safety citation program and delegated authority to the SED to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. (As required by state law, a similar program for electric safety became effective on an interim basis on January 1, 2015. For more information, see "Regulatory Environment" in Item 1.) The California gas corporations are required to inform the SED of self-identified or self-corrected violations. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken.

Since the gas safety program became effective, the Utility has filed approximately 84 self-reports and the SED has imposed fines ranging from $50,000 to $16.8 million (including the $10.85 million fine related to an explosion in Carmel, California that is discussed below) for violations identified through self-reports, SED investigations and audits. The SED recently has stated that it will not conduct further investigations into 65 self-reports the Utility had filed through December 31, 2014. The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility's remaining self-reports or other self-reports that the Utility has filed since January 1, 2015. The Utility believes it is reasonably possible that the SED will impose fines on the Utility based on allegations of noncompliance that are contained in some of the SED's audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

Carmel Incident

On March 3, 2014, a vacant house in Carmel, California was severely damaged due to a natural gas explosion while the Utility's employees were performing work to upgrade the main natural gas distribution pipeline in the area. There were no injuries or fatalities. The SED conducted an investigation of the incident and alleged that the Utility committed two violations of certain natural gas safety regulations by failing to follow procedures to update records, to provide its welding crew with accurate information, and to take steps to make safe any actual or potential hazard to life or property. On November 20, 2014, the SED issued a citation to the Utility that included a fine of $10.85 million for these alleged violations. The Utility recorded this amount as an expense for 2014. The Utility has appealed the citation to the CPUC. The SED has requested that the CPUC dismiss the Utility's appeal as untimely. The CPUC has not yet addressed the SED's request. In addition, the Utility was informed that the U.S. Attorney's Office was investigating the Carmel incident. It is uncertain whether any charges will be brought against the Utility.

CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping

On November 20, 2014, the CPUC issued an order instituting a new investigation into whether the Utility violated applicable laws pertaining to record-keeping practices for its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found.

In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014. (See "Carmel Incident" above.) On December 22, 2014, as directed by the CPUC, the Utility submitted a report that explained why the Utility believes the SED's investigative findings do not constitute violations of law and also outlined the various programs, measures and actions the Utility has undertaken to continuously improve its distribution record keeping practices.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose fines on the Utility or take other enforcement action in connection with this matter, but are unable to reasonably estimate the amount or range of future loss contingencies.

Natural Gas Transmission Pipeline Rights-of-Way

In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

Other Pending Lawsuits and Claims

At December 31, 2014, there were also five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for three of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court in November 2013, which has been amended to add a fourth shareholder plaintiff and to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint for the limited purpose of allowing briefing and hearing on demurrers (state court motions to dismiss). On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the defendant directors and officers and (2) have not adequately pled why such demand should be excused. The court has since clarified that the appropriate board on whom the plaintiffs should have demanded with respect to the claims in the operative complaint is the 2013 PG&E Corporation Board of Directors (and the 2014 Board regarding the allegations first raised in plaintiffs' 2014 amended consolidated complaint). The Court has invited plaintiffs to amend their complaint to accommodate this clarification, and defendants to refile a demurrer on this amended complaint if they so choose. Accordingly, briefing and litigation on this motion is expected to continue through the first quarter of 2015. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. A fifth purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

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

RATEMAKING AND OTHER REGULATORY PROCEEDINGS

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.

2015 Gas Transmission and Storage Rate Case

Utility's GT&S Request

In its December 2013 GT&S rate case application, the Utility requested that the CPUC authorize a 2015 revenue requirement of $1.29 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $555 million over currently authorized amounts. The Utility also requested attrition increases of $61 million in 2016 and $168 million in 2017 based on its forecasted capital expenditures and the associated growth in rate base, as well as increasing costs of labor, materials, and other expenses. 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 $3.56 billion, which includes the capital spend above authorized levels for the prior rate case period. The Utility has not requested authorization to recover approximately $150 million of costs it forecasts it will incur over the three-year period to pressure test pipelines placed into service after 1961 that lack records and perform remedial work associated with the Utility's pipeline corrosion control program. The Utility also has not requested authorization to recover costs it forecasts it will incur during 2015 through 2017 to identify and remove encroachments from its gas transmission pipeline rights-of-way.

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.

Intervenors' Recommendations

The ORA has recommended a 2015 revenue requirement of $1,044 million, an increase of $329 million over authorized amounts, and attrition increases of $39 million for 2016 and $61 million for 2017. The ORA also recommended that the GT&S rate case period be expanded to four years with an attrition increase of $35 million for 2018. The ORA proposed that the CPUC authorize 2015 capital expenditures of $595 million, compared to the Utility's request of $779 million. TURN has stated that it intends to make its revenue requirement recommendation in its opening brief to be filed after hearings conclude on February 27, 2015. Nevertheless, TURN has submitted testimony recommending that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service between January 1, 1956 and June 30, 1961, 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 these capital expenditures 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.

Procedural Schedule

Hearings began on February 2, 2015 and are scheduled to end on February 27, 2015. The current procedural schedule calls for a final decision to be issued in August 2015. The CPUC has stated that if a final CPUC decision is issued in the three investigative enforcement proceedings pending against the Utility within the schedule of the 2015 GT&S rate case, the schedule and scope of issues to be considered may be further amended to consider the implications of that decision on the Utility's revenue requirements.

Order to Show Cause

On September 15, 2014, the Utility notified the CPUC and the ALJ overseeing the 2015 GT&S rate case that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. The CPUC issued an order to show cause why the Utility should not be penalized. On November 20, 2014, the CPUC issued a decision that prohibits the Utility from recovering up to the entire amount of the revenue increase that would have been collected from ratepayers over the five-month period between March 2015 (the date the final decision was originally scheduled to be issued) and August 2015 (the date called for under the revised procedural schedule issued after the Utility's notification of ex parte communications). The decision states that the exact amount of this revenue disallowance will be determined in the CPUC's final decision in the 2015 GT&S rate case. The CPUC also imposed a fine of $1.05 million on the Utility for the violations. (See "Enforcement and Litigation Matters" above regarding additional ex parte communications that were self-reported by the Utility.) The Utility and other parties have filed applications requesting the CPUC to rehear its decision. The ORA, TURN, and the City of San Bruno argue that the applicable law supports the imposition of a fine ranging from $2.5 million to $250 million. It is uncertain when the CPUC will address these applications for rehearing.

Regulatory Accounting

The Utility's continued use of regulatory accounting under GAAP (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) for gas transmission and storage service depends on its ability to recover its cost of service. The Utility's ability to recover its costs of providing gas transmission and storage service will be affected by the outcome of the 2015 GT&S rate case and future GT&S rate cases. If the Utility were unable to continue using regulatory accounting under GAAP, there would be differences in the timing of expense or gain recognition that could materially affect PG&E Corporation's and the Utility's future financial results.

Proposal for Electric Vehicle Infrastructure Development

On February 9, 2015, the Utility filed an application requesting the CPUC to approve the Utility's proposal to deploy, own and maintain EV charging infrastructure in its service territory, including EV retail charging stations, to promote and facilitate the deployment of EVs. Under the Utility's proposal, the Utility would develop EV charging infrastructure over an estimated five years to meet approximately 25% of projected EV charging station needs by 2020. The Utility's EV charging infrastructure is expected to be used in future programs designed to aid the integration of increased intermittent renewable energy on the state's electric power grid. The Utility estimates that it would incur capital costs of $551 million and operating costs of $103 million over the proposed project timeline. The Utility has requested that the CPUC authorize the Utility to collect an average annual revenue requirement over the project development years of $81 million to recover these costs. The Utility has requested that the CPUC issue a decision before the end of 2015.

FERC Transmission Owner Rate Case

The Utility has one TO rate case pending at the FERC. The Utility has requested a 2015 retail electric transmission revenue requirement of $1,366 million, a $326 million increase to the currently authorized revenue requirement of $1,039.6 million (The FERC approved the current revenue requirement on November 7, 2014). The proposed rates will be effective March 1, 2015, subject to refund, pending a final decision by the FERC. The Utility's 2015 cost forecasts reflect the continuing need to replace and modernize aging electric transmission infrastructure, to meet the need for increased capacity in the CAISO controlled grid, and to comply with new rules aimed at ensuring the physical and cyber security of the nation's electric system. The Utility forecasts that it will make investments of $975 million in 2014 and $1,125 million in 2015 in various capital projects. The Utility's proposed rate base for 2015 is $5.12 billion, compared to $4.57 billion in 2014. The Utility has requested that the FERC approve an 11.26% ROE.

The procedural schedule is currently being held in abeyance while settlement discussions are held.

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, 2014, $158 million and $291 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 Note 14 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 market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations; their financing arrangements; the marketplace for electricity, natural gas, electric transmission, natural gas transportation, and storage; emissions allowances, other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as "price risk" (see "Ratemaking Mechanisms" in Item 1) and "interest rate risk." The Utility is also exposed to "credit risk," the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of 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 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.

The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $1 million and $14 million at December 31, 2014 and 2013, respectively. During the 12 months ended

December 31, 2014, the Utility's approximate high, low, and average values-at-risk were $9 million, $1 million and $5 million, respectively. During 2013, the value-at-risk amounts were $14 million, $9 million and $12 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, 2014 and December 31, 2013, 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 $9 million and $11 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

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 ties many energy contracts to 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 credit risk exposure to its counterparties as of December 31, 2014 and December 31, 2013:

(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, 2014	$ 88	$ (18)	$ 70	3	29
December 31, 2013	87	$ (9)	$ 78	2	34

(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

The Utility's rates are primarily set by the CPUC and the FERC and are designed to recover the cost of providing service. 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 that the costs are expected to be 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. In addition, the Utility records regulatory liabilities when the CPUC or the FERC requires a refund to be made to customers or has required that a gain or other reduction of net allowable costs be given to customers over future periods. At December 31, 2014, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of $9.0 billion and regulatory liabilities (including current balancing accounts payable) of $7.6 billion. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

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 2012 through 2014. 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.

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 $116 million, $196 million, and $353 million in 2014, 2013, and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. See "Pipeline Safety Enhancement Plan" in Note 14 of the Notes to the Consolidated Financial Statements in Item 8. The additional charge in 2014 primarily reflects costs for Line 109 (that runs through the San Francisco peninsula) mostly related to emergent permitting conditions and requirements, as well as updated estimates for the few remaining PSEP projects. Management will continue to periodically assess its PSEP 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, 2014 and 2013, the Utility's accruals for undiscounted gross environmental liabilities were $954 million and $900 million, respectively. The Utility's undiscounted future costs could increase to as much as $1.8 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, PG&E Corporation and the Utility are subject to claims or named as parties in lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss 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. These accruals, and the estimates of any additional reasonably possible losses (or reasonably possible losses in excess of the amounts accrued), are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing the amount of such losses, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs. (See "Enforcement and Litigation Matters" and "Legal and Regulatory Contingencies" in Note 14 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, 2014, 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. Additionally, if the inflation adjustment increased 25 basis points, the amount of the ARO would increase by approximately 1.70%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 1.70%.

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. Pension and other benefit expense is based on the differences between actuarial assumptions and actual plan results and is 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 for a portion of the credit balance in accumulated other comprehensive income. (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. During 2014, PG&E Corporation and the Utility adopted the Society of Actuaries 2014 Mortality Tables Report (RP-2014) and Mortality Improvement Scale (MP-2014 with modifications), which adjusted the mortality assumptions used for measuring retirement plan obligations. The updated mortality assumptions reflect increasing life expectancies in the United States, resulting in an increase to PG&E Corporation's and the Utility's pension and PBOP plans' projected benefit obligations. Future pension and postretirement expenses are also expected to increase due to the new mortality assumptions.

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 2014 is 7.5%, gradually decreasing to the ultimate trend rate of 3.5% 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 6.2% compares to a ten-year actual return of 9.3%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 715 Aa-grade non-callable bonds at December 31, 2014. 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 2014 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2014
Discount rate	(0.50	) %	$ 52	$ 1,319
Rate of return on plan assets	(0.50	) %	62	-
Rate of increase in compensation	0.50	%	32	316

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 2014 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2014
Health care cost trend rate	0.50	%	$ 4	$ 53
Discount rate	(0.50	) %	3	128
Rate of return on plan assets	(0.50	) %	9	-

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 are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated 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," "antic "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the final outcomes of the pending CPUC investigations and enforcement matters, the federal criminal prosecution of the Utility, and the other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, including the ultimate amount of fines imposed, whether a monitor is appointed to oversee the Utility's natural gas operations, and the ultimate amount of costs related to the Utility's natural gas operations that is disallowed or unrecoverable;

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

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by negative publicity about the San Bruno accident, the criminal prosecution, the citations issued by the SED against the Utility under the CPUC's gas safety citation program, the state and federal investigations, the CPUC's restrictions on the Utility's communications with the CPUC, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the restrictions on communications between the Utility and the CPUC that have been imposed by the CPUC that, along with continuing public criticism of the Utility and the CPUC, may make it more difficult for the Utility to sustain or repair a constructive working relationship with the CPUC and achieve balanced regulatory outcomes;

- the timing and outcome of ratemaking proceedings (such as the 2015 GT&S rate case and the TO rate case) and whether the cost and revenue forecasts assumed in such outcomes prove to be accurate;

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility's authorized capital structure as the Utility incurs charges and costs that it cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- 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; and whether the current or potentially worsening state regulatory environment increases the likelihood of unfavorable outcomes;

- the impact of environmental laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental costs in rates or from other sources; and the ultimate amount of environmental costs the Utility incurs but does not recover, such as the remediation costs 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; and whether the Utility decides to request that the NRC resume processing the Utility's renewal application for the two Diablo Canyon operating licenses, and if so, whether the NRC grants the renewal;

- the impact of droughts or other weather-related conditions or events, 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; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of CO2 and GHGs, and 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 the cost of renewable energy procurement;

- 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 ROE;

- 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, especially if the integration of renewable generation resources force conventional generation resource providers to curtail production, triggering "take or pay" provisions in the Utility's power purchase agreements;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, 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; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- 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; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- 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 these 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. 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.

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,		
	2014	2013	2012
Operating Revenues			
Electric	$13,658	$12,494	$12,019
Natural gas	3,432	3,104	3,021
Total operating revenues	17,090	15,598	15,040
Operating Expenses			
Cost of electricity	5,615	5,016	4,162
Cost of natural gas	954	968	861
Operating and maintenance	5,638	5,775	6,052
Depreciation, amortization, and decommissioning	2,433	2,077	2,272
Total operating expenses	14,640	13,836	13,347
Operating Income	2,450	1,762	1,693
Interest income	9	9	7
Interest expense	(734)	(715)	(703)
Other income, net	70	40	70
Income Before Income Taxes	1,795	1,096	1,067
Income tax provision	345	268	237
Net Income	1,450	828	830
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	$1,436	$814	$816
Weighted Average Common Shares Outstanding, Basic	468	444	424
Weighted Average Common Shares Outstanding, Diluted	470	445	425
Net Earnings Per Common Share, Basic	$3.07	$1.83	$1.92
Net Earnings Per Common Share, Diluted	$3.06	$1.83	$1.92

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	Year ended December 31, 2014	2013	2012
Net Income	$1,450	$828	$830
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations (net of taxes of $10, $80, and $72, at respective dates)	(14)	113	108
Net change in investments (net of taxes of $17, $26, and $3 at respective dates)	(25)	38	4
Total other comprehensive income (loss)	(39)	151	112
Comprehensive Income	1,411	979	942
Preferred stock dividend requirement of subsidiary	14	14	14
Comprehensive Income Attributable to Common Shareholders	$1,397	$965	$928

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31, 2014	2013
ASSETS		
Current Assets		
Cash and cash equivalents	$151	$296
Restricted cash	298	301
Accounts receivable		
Customers (net of allowance for doubtful accounts of $66 and $80 at December 31, 2014 and 2013, respectively)	960	1,091
Accrued unbilled revenue	776	766
Regulatory balancing accounts	2,266	1,124
Other	377	312
Regulatory assets	444	448
Inventories		
Gas stored underground and fuel oil	172	137
Materials and supplies	304	317
Income taxes receivable	198	574
Other	443	611
Total current assets	6,389	5,977
Property, Plant, and Equipment		
Electric	45,162	42,881
Gas	15,678	14,379
Construction work in progress	2,220	1,834
Other	2	2
Total property, plant, and equipment	63,062	59,096
Accumulated depreciation	(19,121)	(17,844)
Net property, plant, and equipment	43,941	41,252
Other Noncurrent Assets		
Regulatory assets	6,322	4,913
Nuclear decommissioning trusts	2,421	2,342
Income taxes receivable	91	85
Other	963	1,036
Total other noncurrent assets	9,797	8,376
TOTAL ASSETS	$60,127	$55,605

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2014	2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$633	$1,174
Long-term debt, classified as current	-	889
Accounts payable		
Trade creditors	1,244	1,293
Regulatory balancing accounts	1,090	1,008