

PG&E CORP

FORM 10-K (Annual Report)

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2013

Or

☐ 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

PG&E Corporation: Common Stock, no par value
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%

Name of Each Exchange on Which Registered

New York Stock Exchange
NYSE Amex Equities

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

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

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

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

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

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

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

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

PG&E Corporation
Pacific Gas and Electric Company

Yes ☒ No ☐
Yes ☒ No ☐

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

PG&E Corporation
Pacific Gas and Electric Company

☒
☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Exchange Act). (Check one):

PG&E Corporation

Large accelerated filer ☒
Accelerated filer ☐
Non-accelerated filer ☐
Smaller reporting company ☐

Pacific Gas and Electric Company

Large accelerated filer ☐
Accelerated filer ☐
Non-accelerated filer ☒
Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation
Pacific Gas and Electric Company

Yes ☐ No ☒
Yes ☐ No ☒

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2013, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock
Pacific Gas and Electric Company common stock

\$20,326 million
Wholly owned by PG&E Corporation

Common Stock outstanding as of February 3, 2014:

PG&E Corporation: 457,663,407
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 combined 2013 Annual Report to Shareholders	Part I (Items 1, 1A and 3), Part II (Items 5, 6, 7, 7A, 8 and 9A)
Designated portions of the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

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

GLOSSARY

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

2013 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, 2013, including the information incorporated by reference into the report
AB 32	California Global Warming Solutions Act of 2006
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community choice aggregator
CEC	California Energy Commission
Central Coast Board	Central Coast Regional Water Quality Control Board
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CO ₂	carbon dioxide
CO ₂ -e	CO ₂ -equivalent
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DOE	U.S. Department of Energy
EPA	Environmental Protection Agency
ERRA	Energy Resource Recovery Account
ESC	Engineers and Scientists of California
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GRC	general rate case
GTN	Gas Transmission Northwest Corporation
GT&S	gas transmission and storage
IBEW	International Brotherhood of Electrical Workers
LTIP	PG&E Corporation long-term incentive plan
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGP	manufactured gas plant
NERC	North American Electric Reliability Corporation
NO _x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
ORA	Office of Ratepayer Advocates
OSC	CPUC Order to Show Cause
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	pipeline safety enhancement plan
PV	photovoltaic
QF(s)	qualified facilities
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
SEIU	Service Employees International Union, United Service Workers West
SO ₂	sulfur dioxide
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
WECC	Western Interconnection to the Western Electricity Coordinating Council

PART I

ITEM 1. Business

General

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 on January 1, 1997. The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas to customers.

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. PG&E Corporation and the Utility file or furnish various reports with the SEC. These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Exchange Act, 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 incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

This is a combined Annual Report on Form 10-K of PG&E Corporation and the Utility and includes information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2013, which is attached to this report as Exhibit 13 and the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders. The 2013 Annual Report 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 the information in the 2013 Annual Report under the headings "Cautionary Language Regarding Forward-Looking Statements" and "Risk Factors" which appear under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Natural Gas Operations

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's PSEP, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the rupture of one of the Utility's natural gas transmission pipelines in San Bruno, California on September 9, 2010 (the "San Bruno accident"). (For more information, see "Natural Gas Utility Operations" below.)

During 2013, the Utility settled the majority of the civil lawsuits that were filed after the San Bruno accident. The CPUC investigations and the criminal investigation that were commenced after the San Bruno accident are still unresolved. The CPUC's SED also may take enforcement action with respect to numerous reports the Utility has filed to report noncompliance with various natural gas regulations. See information under the headings within MD&A entitled "Natural Gas Matters" and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report which information is incorporated herein by reference.

Electricity Operations

During 2013, the Utility made significant capital investments to improve and modernize its electricity operations by repairing, replacing, or upgrading equipment to improve safety and reliability. The Utility has substantially completed the installation of advanced electric and gas meters throughout its service territory and continued taking steps to lay the foundation for the development of a “smart grid” to enable customers to have better control over their energy usage and costs, to integrate new sources of energy, and to enable the continued safe and reliable operation of the grid. In 2013, the Utility received regulatory approval to pilot and test new “smart grid” technologies that have the potential to support the provision of safe, reliable and affordable electric service. (For more information, see “Electric Utility Operations” below.)

Employees

At December 31, 2013, PG&E Corporation and its subsidiaries had 21,166 regular employees, including 21,159 regular employees of the Utility. Of the Utility’s regular employees, 13,150 are covered by collective bargaining agreements with three labor unions: the IBEW; the ESC; and the SEIU. There are two collective bargaining agreements with IBEW. Both bargaining agreements expire on December 31, 2014. The ESC collective bargaining agreement also expires on December 31, 2014. The SEIU collective bargaining agreement expires on July 31, 2015.

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. For discussion of specific pending regulatory matters that are expected to affect the Utility, see the information under the headings within MD&A entitled “Regulatory Matters” and “Natural Gas Matters” in the 2013 Annual Report, which information is incorporated herein by reference.

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 of 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.

Federal Regulation

The Federal Energy Regulatory Commission

The FERC regulates the transmission of electricity and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities, tariffs and conditions of service of regional transmission organizations, including the CAISO, and the terms and rates of wholesale electricity sales. The FERC has authority to impose fines of up to \$1 million per day for violation of certain federal statutes and regulations. 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 has the responsibility to approve and enforce 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, to prevent market manipulation, and to supplement state transmission siting efforts in certain electric transmission corridors that are determined to be of national interest. The FERC certified the NERC as the nation’s Electric Reliability Organization. The NERC is responsible for developing and enforcing electric reliability standards, subject to FERC approval. The FERC also has approved a delegation agreement under which the NERC has delegated enforcement authority for the geographic area known as the Western Interconnection to the Western Electricity Coordinating Council. The Utility must self-certify compliance to the WECC on an annual basis and the compliance program encourages self-reporting of violations. WECC staff, with participation by the NERC and the FERC, also performs a compliance audit of the Utility every three years. The FERC also has authorized the WECC and the NERC to impose fines up to \$1 million per day, per violation.

The FERC also has adopted policies and rules to promote investment in energy infrastructure and lower costs for consumers through incentive ratemaking for transmission projects. In addition, the FERC’s Order No. 1000 establishes electric transmission planning and cost allocation requirements for public utility transmission providers. Order No. 1000 requires public utility transmission providers to improve transmission planning processes and allocate costs for new transmission facilities to the beneficiaries of those facilities.

The CAISO is responsible for providing open access electricity transmission service on a non-discriminatory basis, planning transmission system additions, and ensuring the maintenance of adequate reserves of generation capacity.

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. 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 additional significant capital expenditures could be required in the future. For information about NRC matters affecting Diablo Canyon, including the status of the Utility's relicensing application see the information under the heading within MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" in the 2013 Annual Report, which information is incorporated herein by reference.

The Pipeline and Hazardous Materials Safety Administration

The Utility also is subject to regulations adopted by the federal PHMSA that is within the United States Department of Transportation. The PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's pipeline transportation system and the shipment of hazardous materials. The PHMSA also has authorized the CPUC to enforce the federal pipeline safety standards over intrastate natural gas pipelines, as well as any state pipeline safety requirements that do not conflict with the federal requirements, through fines and/or injunctive relief.

The National Transportation Safety Board

The NTSB is an independent federal agency that is authorized to investigate pipeline accidents and certain transportation accidents that involve fatalities, substantial property damage, or significant environmental damage. The NTSB investigated the San Bruno accident and in August 2011 announced that it had determined the probable cause of the San Bruno accident placing the blame primarily on the Utility. The NTSB report recommended that the Utility take certain actions to improve the safety of its gas transmission system. The status of the Utility's implementation of the NTSB's recommendations is discussed under "Natural Gas Utility Operations" below.

State Regulation

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 transportation and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas gathering, transmission, and distribution pipeline systems, and for the safe operation of such pipelines and equipment. The CPUC has adopted many rules and regulations to implement state laws and policies, such as the laws relating to the development of renewable energy resources, demand response and public purpose programs, reduction of GHG emissions, and development of energy storage capacity. As discussed above, the CPUC also has been delegated authority to enforce compliance with certain federal regulations related to the safety of natural gas facilities. The CPUC has authority to impose fines for violating these state and federal laws, orders, or regulations of up to \$50,000 per violation, per day. (See the discussion under the heading within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report for information about the CPUC's pending enforcement proceedings against the Utility relating to the Utility's gas operations, which discussion is incorporated herein by reference.)

In addition, California law enacted in 2013 requires the CPUC to develop a safety enforcement program that authorizes CPUC staff to issue citations for safety violations and assess fines subject to a CPUC-approved limit. The CPUC is required to implement the safety enforcement program for gas corporations by July 1, 2014 and for electric corporations by January 1, 2015. (See the discussion under the heading within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report for information about the reports the Utility has filed to notify the CPUC staff of noncompliance with certain gas safety regulations.)

Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent that this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC has general jurisdiction over most of the Utility's operations, and regularly reviews the Utility's performance, using measures such as the frequency and duration of outages. The CPUC also conducts investigations into various matters, such as deregulation, competition, and the environment, in order to determine its future policies.

The CPUC has imposed conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates. These conditions relate to finance, human resources, records and bookkeeping, and the transfer of customer information. Among other conditions, the financial conditions provide that 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, must be given first priority by PG&E Corporation's Board of Directors (known as the "first priority" condition). In addition, the Utility must maintain on average its CPUC-authorized utility capital structure, although it can request a waiver of this condition if an adverse financial event reduces the Utility's common equity component by 1% or more. The CPUC also has adopted rules governing transactions between California's CPUC-regulated electricity and gas utilities and certain of their affiliates that are not regulated by the CPUC primarily to prevent these affiliates from gaining an unfair advantage over their unaffiliated competitors.

The California Energy Resources Conservation and Development Commission

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, overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development and demonstration, and providing market support to existing, new, and emerging renewable technologies. 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 California Air Resources Board

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 meet the AB 32, which requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2013. (For more information, see "Environmental Matters — Air Quality and Climate Change" below.)

Other Regulation

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. These permits include discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses. (For more information, see "Environmental Matters — Water Quality" below.)

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. The Utility has several franchise agreements that have a specified term of years, including an agreement with a large charter city.

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.

Competition in the Electricity Industry

At the federal level, the FERC is charged with developing rules to encourage fair and efficient competitive wholesale electric markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. (See "Regulatory Environment—Federal Regulation" above for a description of some of these rules.) The FERC also has authority to prevent accumulation and exercise of market power by assuring that proposed mergers and acquisitions of public utility companies and their holding companies are in the public interest and by addressing market power in jurisdictional wholesale markets through its new powers to establish and enforce rules prohibiting market manipulation. The FERC also has issued rules on the interconnection of generators to require regulated transmission providers, such as the Utility or the CAISO, to use standard interconnection procedures and a standard agreement for generator interconnections. These rules are intended to limit opportunities for electric transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage investment in generation and transmission.

In 1998, California became one of the first states to (1) allow customers of the California investor-owned electric utilities to purchase electricity from energy service providers other than the regulated utilities (referred to as “direct access”) and (2) establish a competitive market for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity. The wholesale electricity market failed to function as anticipated leading to the 2000-2001 California energy crisis, the suspension of direct access, and the Utility’s reorganization under Chapter 11 of the U.S. Bankruptcy Code. (For information about the unresolved disputed claims made by power suppliers in the Utility’s Chapter 11 proceeding, see Note 12: Resolution of Remaining Chapter 11 Disputed Claims, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

Current California law allows for the gradual phase-in of direct access subject to annual and overall limits (measured in GWh) that have been specified for each utility based roughly on each utility’s highest level of direct access before the CPUC suspended direct access. A four-year phase-in period began in April 2010 to allow qualifying non-residential customers of the three California investor-owned electric utilities to purchase electricity from alternate service providers, subject to the limits. The Utility’s maximum, 9,520 GWh, was reached in November 2013. Although the Utility’s total amount of direct access load may increase due to natural load growth for existing direct access customers, further legislative action is required before new customers can be enrolled in excess of these limits.

In addition, 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 purchase and sell electricity for their local residents and businesses after they have registered as CCAs. Under these arrangements, the Utility continues to provide 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. Under the CPUC’s rules, a surcharge is imposed on retail end-users of the CCA to prevent a shifting of costs to customers who continue to receive electricity from a utility. The law also authorizes the Utility 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. Approximately 125,000 customers are now receiving commodity service from the Marin Energy Authority, a CCA. Sonoma Clean Power, another CCA, is expected to begin service to a subset of customers in Sonoma County in May 2014.

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. For example, South San Joaquin Irrigation District has indicated that, if it receives the requested authority to provide electric distribution service in and around certain cities (Manteca, Ripon, and Escalon), it will seek to acquire the Utility’s distribution facilities, either under a consensual transaction, or via eminent domain.

It is also possible that technological developments could pose challenges for traditional utilities. In particular, technology-related cost declines and sustained federal or state subsidies could make the combination of “distributed generation” and storage a viable, cost-effective alternative to the Utility’s bundled electric service. In addition, 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.

Although the CPUC has established ratemaking mechanisms that allow the Utility to collect some non-bypassable or fixed charges from those who procure electricity from alternate sources, rates for the Utility’s remaining customers could increase as alternative energy providers (CCAs or local government agencies) and alternative energy sources (self-generation and storage, distributed generation, electric vehicles) become more prevalent. Increasing rate pressure on remaining customers could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the Utility’s rate challenges. New state legislation that became effective on January 1, 2014 (Assembly Bill 327) gave the CPUC new authority to reduce the cost shift associated with customers installing renewable distributed generation under the net energy metering rules.

In addition, the Utility competes with third parties to make various capital investments such as new utility-owned generation facilities, electric transmission projects, SmartGrid electric reliability projects, and distributed generation technologies. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

Competition in the Natural Gas Industry

Under the FERC's rules, interstate natural gas pipeline companies are required to divide their services into separate gas commodity sales, transportation, and storage services and must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas from these companies. The Utility's natural gas pipelines are located within the State of California and are exempt from most of the FERC's rules and regulations applicable to interstate pipelines; the Utility's pipeline operations are instead subject to the jurisdiction of the CPUC.

The Utility's gas transmission and storage system has operated under the CPUC-approved "Gas Accord" market structure since 1998 which largely mimics the regulatory framework required by the FERC for interstate gas pipelines. (See "Ratemaking Mechanisms" below.) The CPUC divides the Utility's natural gas customers into two categories: "core" customers, who are primarily small commercial and residential customers, and "non-core" customers, who are primarily industrial, large commercial, and electric generation customers. Although most of the Utility's core customers purchase natural gas directly from the Utility (along with transportation and distribution services as bundled services), core customers have the option to purchase natural gas from independent, unregulated natural gas marketers. Most of the Utility's noncore customers make natural gas supply arrangements directly with producers or purchase natural gas from marketers.

Non-core customers have access to capacity rights for firm service on the Utility's natural gas pipeline, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. This market structure has resulted in a robust wholesale gas commodity market at the Utility's "Citygate," which refers to the non-physical interconnection between the big "backbone" gas transmission system and the smaller downstream local transmission systems.

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California, relative to the total delivered cost of natural gas from the southwestern United States. In general, when the total cost of western Canadian and U.S. Rocky Mountains natural gas delivered to northern California increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

In addition, the Utility competes with third parties to make various capital investments—such as new natural gas storage facilities. The Utility generally participates through a competitive requests-for-offers process that is subject to the oversight of the CPUC or the FERC. If the Utility is selected as the winning bidder, the Utility submits the executed contract for regulatory approval and cost recovery authorization.

Ratemaking Mechanisms

The Utility's rates for electricity and natural gas utility services are based on its costs of providing service ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The Utility's revenue requirements are set based on forecasted costs. Differences in the amount or timing between forecast costs and actual costs could negatively affect the Utility's ability to earn its authorized return.

To develop retail rates, the 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. Most rate changes approved by the CPUC throughout the year are consolidated to take effect on the first day of the following year.

California Assembly Bill 327, 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. The CPUC has ordered the California investor-owned utilities, including the Utility, to file proposals for changing residential rates that are consistent with the new law. The current procedural schedule calls for a final decision in the first half of 2014 to approve changes to the Utility's residential electric rates for summer 2014, and a final decision by year-end 2014 to approve broader changes in residential electric rates.

While the CPUC generally uses cost-of-service ratemaking to develop revenue requirements and rates, it selectively uses incentive ratemaking, which bases rates on the extent to which the utilities meet objective or fixed standards or goals, such as energy efficiency goals, instead of on the cost of providing service. See "Public Purpose and Customer Programs" below.

Electricity and Natural Gas Distribution and Electricity Generation Operations

General Rate Cases

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated costs related to its electricity and natural gas distribution and electricity generation operations and to provide the Utility an opportunity to earn its authorized rate of return. 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 provided to avoid a reduction in earnings due to, among other things, inflation and increases in invested capital. Intervenor in the Utility's GRC include the CPUC's ORA and TURN, who generally represent the overall interests of customers, as well as a myriad of other intervenors who represent more limited interests.

In November 2012, the Utility filed its 2014 GRC application with the CPUC for rates effective from 2014 through 2016. The CPUC has concluded evidentiary hearings and briefing in the 2014 GRC and the Utility is now waiting for the CPUC to issue a proposed decision. For more information see the heading within MD&A entitled "Regulatory Matters – 2014 General Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

In November 2013, the CPUC opened a proceeding to consider modifications to the processing and content of GRCs (and for the Utility's GT&S rate cases) to better integrate and prioritize safety, reliability, and security issues by developing a risk-based decision-making framework for the CPUC to use in evaluating the utilities' requested revenue requirements. The CPUC also will consider whether to change the current three-year rate case cycle and whether to retain the requirement that the ORA review a draft of the utilities' GRC applications prior to filing. A decision is expected to be issued in late 2014.

Cost of Capital Proceedings

The CPUC authorizes the Utility's capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rates of return on each component that the Utility may earn on 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 2015, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also authorized the Utility to earn a ROE of 10.40% effective January 1, 2013, compared to the 11.35% previously authorized. The Utility's ROE can be automatically adjusted if the 12-month October-through-September average of the Moody's Investors Service long-term Baa utility bond index increases or decreases by more than 1.00% as compared to the applicable benchmark. If the adjustment mechanism is triggered, the Utility's authorized ROE, beginning January 1 of the following year, would be adjusted by one-half of the difference between the index and the benchmark. Additionally, the Utility's authorized costs of long-term debt and preferred stock would be updated to reflect actual August month-end embedded costs and forecasted interest rates for variable long-term debt, as well as new long-term debt and preferred stock scheduled to be issued. In any year where the 12-month average yield triggers an automatic ROE adjustment, that average would become the new benchmark.

The Utility will file its next full cost of capital application in April 2015 for the 2016 test year.

Rate Recovery of Costs of Electricity Generation Resources

California investor-owned electric utilities are required to use the principles of “least-cost dispatch” in managing electric generation resources to meet customer demand for electricity. The utilities are also 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. To accomplish this, each utility must submit a ten-year procurement plan to the CPUC for approval. Each procurement plan must be designed to use the State of California’s preferred loading order to meet the forecasted demand (i.e., increases in future demand will be offset through energy efficiency programs, demand response programs, renewable generation resources, distributed generation resources, and new conventional generation). The CPUC approved the Utility’s electricity procurement plan in January 2012 covering 2011 through 2020 and approved the Utility’s GHG compliance instrument procurement plan in April 2012.

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. To the extent the Utility’s electricity purchases are not in compliance with the CPUC-approved plan, costs associated with those purchases may be disallowed. The Utility recovers its electricity procurement costs through the ERRA, a balancing account authorized by the CPUC, that tracks the difference between (1) billed and unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility’s authorized procurement plans. Each year, to determine the rates used to collect ERRA revenues, the CPUC reviews the Utility’s forecasted procurement costs related to power purchase agreements, hedging, and generation fuel expense and approves a forecasted revenue requirement.

On December 19, 2013, the CPUC approved the Utility’s forecast of 2014 procurement costs and associated revenue requirement. Changes in rates to reflect the approved revenue requirement became effective on January 1, 2014. (The CPUC may adjust a utility’s retail electricity rates at any time when the forecasted aggregate over-collections or under-collections in the ERRA exceed five percent of its prior year electricity procurement revenues.) The CPUC also performs an annual compliance review to ensure that (1) the Utility prudently administered the contracts that were entered into in accordance with its CPUC-approved procurement plans, (2) utilized the principles of least-cost dispatch in managing its electric generation resources, and (3) prudently operated its own generation facilities.

Costs Incurred Under New Power Purchase Agreements

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 and has authorized the Utility to recover costs associated with these contracts through the ERRA.

For new non-renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through either (1) a non-bypassable customer charge or (2) the allocation of the “net capacity costs” (i.e., contract price less energy revenues) to all “benefiting customers” in the Utility’s service territory, including direct access customers and CCA customers under certain circumstances. The non-bypassable charge can be imposed from the date of signing a power purchase agreement and can last for ten years from the date the new generation unit comes on line or for the term of the contract, whichever is less. Utilities are allowed to justify a cost recovery period longer than ten years on a case-by-case basis. If a utility uses the net capacity cost allocation method, the net capacity costs are allocated for the term of the contract. To use the net capacity allocation method, the CPUC must determine that a resource was needed to meet system or local area reliability needs for the benefit of all distribution customers. The CPUC can decide whether to require an energy auction for resources subject to the net capacity cost allocation.

For renewable generation purchased from third parties under power purchase agreements, the Utility may also recover any above-market costs through the imposition of a non-bypassable charge on customers.

Costs of Utility-Owned Generation Resource Projects

The Utility's recovery of its capital costs and non-fuel operating and maintenance costs for Utility-owned generation facilities is addressed in the Utility's GRC. From time to time, the Utility may also request the CPUC to authorize additional revenue requirements to recover capital investments and operating costs associated with new Utility-owned generation facilities in a separate ratemaking proceeding. The Utility may recover any above-market costs associated with new utility-owned generation resources in a manner similar to the recovery of above-market costs for non-renewable generation purchases described above. The recovery of above-market costs is typically addressed in the CPUC order approving a specific utility-owned generation project.

Electricity Transmission

The Utility's electricity transmission revenue requirements and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two main sources of transmission revenues: (1) charges under the Utility's TO tariff and (2) charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in 1998. These wholesale customers are referred to as existing transmission contract customers and are charged individualized rates based on the terms of their contracts. Other customers pay transmission rates that are established by the FERC in the Utility's TO tariff rate cases. These FERC-approved rates are included by the CPUC in the Utility's retail electric rates and are collected from retail electric customers receiving bundled service.

TO Rate Cases

The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility is authorized to recover for its electric transmission costs and to earn its return on equity is the TO rate case. The Utility generally files a TO rate case every year. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. See the information within MD&A entitled "Electric Transmission Owner Rate Cases" in the 2013 Annual Report, which information is incorporated herein by reference.

The Utility's TO tariff includes several rate components. The primary component consists of base transmission rates intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense, and return on equity. The Utility derives the majority of the Utility's transmission revenue from base transmission rates. Another component consists of rates that reflect credits and charges from the CAISO for transmission revenues received by the CAISO for providing wholesale wheeling service (i.e., the transfer of electricity that is being sold in the wholesale market) to third parties using the Utility's transmission facilities and charges related to the cost of providing service to existing transmission contract customers under specific contracts. The CAISO also imposes a transmission access charge on the Utility for use of the CAISO-controlled electric transmission grid in serving its customers, which are recovered from the Utility's retail customers as part of transmission rates.

Natural Gas Transmission

Costs Incurred Under the Pipeline Safety Enhancement Plan

Following the San Bruno accident, the CPUC began a rulemaking proceeding in 2011 to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. As part of this proceeding, the CPUC ordered the California natural gas utilities to submit proposed plans to modernize and upgrade their natural gas transmission systems, including cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP but disallowed the Utility's request for rate recovery of a significant portion of PSEP-related costs that the Utility forecasted it would incur through 2014. The CPUC authorized the Utility to recover costs, subject to the adopted capital and expense amounts, for activities including pipeline strength testing, pipeline replacement, in-line inspection, and the installation of automated valves. The CPUC prohibited the Utility from recovering the costs of pressure testing pipeline placed into service after January 1, 1956 for which the Utility is unable to produce pressure test records. The CPUC ordered the Utility to file an update PSEP application after the Utility completes its search and review of records relating to pipeline pressure validation for all 6,750 miles of the Utility's natural gas transmission pipelines. On October 29, 2013, the Utility submitted its update application to present the results of its completed records search and review and to request approval of adjusted revenue requirements for 2014. Based on the information obtained through the records search and review, the Utility has proposed to change the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects. See the information under the headings within MD&A entitled "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.

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 a separate rate case called the GT&S rate case. The CPUC's decision in the most recent GT&S rate case approved a settlement agreement, known as the Gas Accord V, which set the Utility's rates and associated revenue requirements for natural gas transmission and storage services from January 1, 2011 through December 31, 2014. In December 2013, the Utility filed its 2015 GT&S rate case application with the CPUC covering 2015 through 2017. The Utility's forecasts for the 2015 GT&S rate case period are consistent with state law, which requires gas corporations to develop a plan to identify and minimize hazards and systemic risk for public and employee safety. The forecasts include the continuation of work begun in the Utility's PSEP, such as testing pipelines to verify safe operating pressures, replacing older pipelines, installing more valves, and inspecting the interior of more pipelines. The Utility forecasts that it will incur certain costs that it will not seek to recover from customers. See the information under the heading within MD&A entitled "2015 Gas Transmission and Storage Rate Case" in the 2013 Annual Report, which information is incorporated herein by reference.

Under the current ratemaking mechanisms (which have been in existence since 1998 when the first Gas Accord settlement agreement became effective), the Utility's ability to recover a portion of its revenue requirements depends on throughput volumes, gas prices, and the extent to which large industrial customers, large commercial customers, and other shippers contract for firm transmission services. In its 2015 GT&S rate case application, the Utility has proposed eliminating these current mechanisms and that the CPUC establish new two-way balancing accounts to allow the Utility to record differences between actual customer billings and the Utility's authorized revenue requirements for natural gas transmission and storage revenues. Any over-collections would be returned to customers and any under-collections would be paid by customers.

Under the current ratemaking mechanisms, revenue requirements allocated to core customers are decoupled and recovered through balancing accounts that ensure the Utility recovers only its adopted amounts, no more or less. Revenue requirements allocated to non-core customers are subject to a sharing mechanism. Annually, differences between the authorized revenue requirements and actual customer billings are shared between customers and the Utility's shareholders to varying degrees, depending on the type of service. The Utility is currently at risk for approximately 25% of its total authorized GT&S revenue requirements. In its 2015 GT&S rate case application, the Utility has proposed to discontinue the sharing mechanism and to, instead, recover its non-core revenue requirements in the same decoupled manner as its core revenue requirements through existing balancing accounts. Non-core customers are typically large commercial, industrial, electric generation or wholesale customers who meet required usage requirements. These customers must obtain their own gas procurement and are subject to curtailment.

Biennial Cost Allocation Proceeding

Certain of the Utility's natural gas distribution costs and balancing account balances are allocated to customers in the CPUC's Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any over-collection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

Natural Gas Procurement

The Utility recovers the cost of gas purchased on behalf of core customers, as well as some core hedging costs, through its retail gas rates subject to a limited incentive mechanism based on a market-priced benchmark. The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered through retail electricity rates. (For more information, see Note 9: Derivatives, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference).

Interstate and Canadian Natural Gas Transportation

The Utility has a number of agreements with interstate and Canadian third-party transportation service providers to 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 are governed by 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 electricity procurement costs. For more information, see the discussion below under "Natural Gas Utility Operations — Interstate and Canadian Natural Gas Transportation Services Agreements" below.

Electric Utility Operations

During 2013, the Utility made significant capital investments to modernize and upgrade its electric transmission and distribution infrastructure to extend the life of or replace existing infrastructure; to maintain and improve system reliability, safety, and customer service; to integrate more renewable energy resources; to increase capacity; and add new infrastructure to meet customer demand growth. The Utility improved the reliability of its system by adding emergency capacity at substations, increasing distribution system automation, upgrading poor performing circuits, performing targeted asset replacement, and improving service outage restoration processes. The Utility also has been working to accelerate pole replacement and maintenance of its overhead and underground electric facilities and to increase the use of wireless devices that allow the Utility to monitor the performance of the electric system and respond more quickly to power disruptions.

The Utility's advanced metering infrastructure supports the development of a "smart grid" in California, part of a nationwide effort to improve and modernize the nation's electric system by combining advanced communications and controls to create a responsive and resilient energy delivery network. The Utility has substantially completed the installation of an advanced metering infrastructure throughout its service territory in 2012. (As permitted by CPUC rules, customers may choose not to have an advanced meter installed.) The new infrastructure uses SmartMeter™ technology that can measure energy use in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communications network and transmitted to

the Utility’s information system where the data is stored and used for billing and other Utility business purposes.

The Utility is also incorporating the latest “smart grid” technology in parts of its service territory by installing automated switches that reduce outage duration and the number of customers affected by outages. The Utility also received regulatory approval to pilot and test new “smart grid” technologies that have the potential to support the provision of safe, reliable and affordable electric service. Over the next several years, the Utility plans to undertake various “smart grid” projects and invest in “smart grid” technologies.

Electricity Resources

The Utility is required to maintain physical generating capacity adequate to meet its customers' 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 actual deliveries of electricity to customers in 2013 represented by each major electricity resource, and further discussed below.

Total 2013 Actual Electricity Delivered – 75,705 GWh:

	Percent of Bundled Retail Sales
Owned Generation Facilities	
Nuclear	23.8%
Small Hydroelectric	1.2%
Large Hydroelectric	9.4%
Fossil fuel-fired	8.1%
Solar	0.4%
Total	42.9%
Qualifying Facilities	
Renewable	4.1%
Non-Renewable	8.9%
Total	13.0%
Irrigation Districts and Water Agencies	
Small Hydroelectric	0.2%
Large Hydroelectric	1.9%
Total	2.1%
Other Third-Party Purchase Agreements	
Renewable	16.6%
Large Hydroelectric	0.6%
Non-Renewable	13.0%
Total	30.2%
Others, Net ⁽¹⁾	11.8%
Total	100%

⁽¹⁾ Mainly comprised of net CAISO open market purchases, offset by transmission and distribution related system losses.

Owned Generation Facilities

At December 31, 2013, 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:			
Diablo Canyon	San Luis Obispo	2	2,240
Hydroelectric:			
Conventional	16 counties in northern and central California	104	2,670
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal:		107	3,882
Fossil fuel-fired:			
Colusa Generating Station	Colusa	1	657
Gateway Generating Station	Contra Costa	1	580
Humboldt Bay Generating Station	Humboldt	10	163
CSU East Bay Fuel Cell	Alameda	1	1.4
SF State Fuel Cell	San Francisco	2	1.6
Fossil fuel-fired subtotal:		15	1,403
Photovoltaic:	Various	13	152
Total		137	7,677

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the year ended December 31, 2013, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 92%. The NRC operating license for Unit 1 expires in November 2024, and the NRC operating license for Unit 2 expires in August 2025. For more information on matters affecting Diablo Canyon, see the section of MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" in the 2013 Annual

Report, which information is incorporated herein by reference. 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. For more information about these agreements, see Note 14: Commitments and Contingencies — Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. 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.

	2014	2015	2016	2017	2018
Unit 1					
Refueling	February	September	-	April	-
Startup	March	November	-	May	-
Unit 2					
Refueling	October	-	May	-	February
Startup	November	-	June	-	March

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 107 generating units at 67 powerhouses, including the Helms pumped storage facility. Most of the Utility's hydroelectric generation units are classified as "large" hydro facilities, as their powerhouse capacity exceeds 30 MW. The system includes 98 reservoirs, 73 diversions, 169 dams, 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, 65 miles of pipe (penstocks, siphons and low head pipes), and 4 miles of natural waterways, and approximately 140,000 acres of fee-owned land. The system also includes water rights as specified in 89 permits or licenses and 160 statements of water diversion and use. The Helms pumped storage facility consists of three motor/generator units.

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. The Utility is in the process of renewing hydroelectric licenses associated with capacity of approximately 1,138 MW and surrendering the hydroelectric license associated with the Kilarc-Cow Creek Project which has a capacity of 5 MW. Although the original licenses associated with 1,070 MW of the 1,138 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,812 MW of hydroelectric power will expire between 2014 and 2047.

Fossil Fuel-fired Generation Facilities. The Utility's natural gas-fired generation facilities include the Colusa Generating Station, the Gateway Generating Station, and the Humboldt Bay generating station. In addition, the Utility owns and operates three fuel cell sites in the Bay Area.

Photovoltaic Facilities. The Utility's operational PV 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

Qualifying Facility Power Purchase Agreements. In accordance with the Public Utility Regulatory Policies Act of 1978, the CPUC required electric utilities to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility. QFs primarily include small production facilities whose primary energy sources are co-generation facilities that produce combined heat and power and renewable generation facilities. As of December 31, 2013, the Utility had agreements with 170 QFs that are in operation, which expire at various dates between 2014 and 2028.

Irrigation Districts and Water Agencies. The Utility also has entered into agreements with various irrigation districts and water agencies to purchase hydroelectric power. These agreements require the Utility to make semi-annual fixed minimum payments as well as variable payments based on the operating and maintenance costs incurred by the irrigation districts and water agencies. These contracts will expire on various dates between 2014 and 2030.

Other Third-Party Power Purchase Agreements. The Utility has entered into several power purchase agreements for renewable and conventional generation resources, including tolling agreements and resource adequacy agreements.

For more information regarding the Utility's power purchase agreements, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

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. The RPS program, which 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. In 2013, the California law that established the RPS program was amended to allow the CPUC to set higher RPS targets. The CPUC is conducting a rulemaking proceeding to consider, among other issues, whether and how to increase the RPS targets. Renewable generation resources, for purposes of the RPS program, include bioenergy such as biogas and biomass, certain (primarily small) hydroelectric facilities and efficiency improvements, wind, solar, and geothermal energy. The Utility has made substantial financial commitments under third-party renewable energy contracts to meet its RPS requirements. The Utility forecasts that it will comply with its RPS requirements for the first and second compliance periods based on its current portfolio of executed contracts. The costs incurred by the Utility under third-party contracts to meet RPS requirements are expected to be recovered with other procurement costs through rates. The costs of Utility-owned renewable generation projects will be recoverable through traditional cost-of-service ratemaking mechanisms provided that costs do not exceed the maximum amounts authorized by the CPUC for the respective project.

During 2013, most renewable energy deliveries resulted from third party power purchase agreements and QF agreements. Additional renewable resources included the Utility's small hydroelectric and solar facilities and certain irrigation district contracts (small hydroelectric facilities). (Under California law, generally only small hydroelectric generation resources (30 MW or less) can qualify as a renewable resource for purposes of meeting the RPS mandate, with some exceptions. Most of the Utility's hydroelectric generating units have a capacity in excess of the 30-MW threshold and do not qualify as RPS-eligible resources.)

Total 2013 renewable deliveries are stated in the table below.

Type	GWh	Percent of Bundled Retail Sales
Biopower	3,239	4.3%
Geothermal	3,693	4.9%
Wind	4,904	6.5%
RPS-Eligible Hydroelectric	1,581	2.1%
Solar	3,613	4.7%
Total	17,030	22.5%

For more information regarding the Utility's renewable energy contracts, see Note 14: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Electricity Transmission

At December 31, 2013, the Utility owned approximately 18,115 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV. The Utility also operated 91 electric transmission substations with a capacity of approximately 62,289 MVA. The Utility's electric transmission system is interconnected with electric power systems in the WECC, which includes many western states, Alberta and British Columbia, Canada, and parts of Mexico.

The CAISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The CAISO also is responsible for ensuring that the reliability of the transmission system is maintained. The Utility acts as its own scheduling coordinator to schedule electricity deliveries to the transmission grid. The Utility also acts as a scheduling coordinator to deliver electricity produced by several governmental entities to the transmission grid under contracts the Utility entered into with these entities before the CAISO commenced operation in 1998. In addition, under the mandatory reliability standards implemented by the FERC, all users, owners, and operators of the transmission system, including the Utility, are also responsible for maintaining reliability through compliance with the reliability standards. See the discussion of reliability standards under "The Utility's Regulatory Environment — Federal Regulation" above.

In November 2013, the Utility, MidAmerican Transmission LLC, and Citizens Energy Corporation were selected by CAISO to develop a new 70-mile transmission line to address the growing power demand in the greater Fresno area. The 230-kV line will span across Fresno, Madera and Kings counties, running from the Gates to Gregg substations, which are owned and operated by the Utility. In addition to increased power, the new line will help reduce the number and duration of power outages, create jobs and support economic development, and bolster efforts to integrate clean, renewable energy onto the grid. The transmission line would be operational no later than 2022 and could come on line earlier.

During 2013, the Utility upgraded several critical substations and re-conducted some transmission lines to improve maintenance and operating flexibility, reliability and safety, including the installation or replacement of 8 transmission substation transformers. The Utility expects to undertake various additional transmission projects over the next few years to upgrade and expand the Utility's transmission system and increase capacity in order to accommodate system load growth, to secure access to renewable generation resources, to replace aging or obsolete equipment, and to improve system reliability. The Utility also has taken steps to improve the physical security of its transmission substations and equipment following the attack on one of its transmission substations in April 2013 which caused significant damage.

Electricity Distribution

The Utility's electricity distribution network consists of approximately 141,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 58 transmission-switching substations, and 603 distribution substations. The Utility's distribution network interconnects with the Utility's transmission system primarily at transmission switching substations and distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers.

The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices, and structural equipment. 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 lines or other facilities to entities, such as municipal and other utilities, that then resell the electricity. In April 2013, the Utility began construction on the first of three new electric distribution control centers that will house new smart grid technology, enhancing electric reliability for customers. Located in Concord, California, the 37,000-square-foot facility is expected to be completed in 2014.

In 2013, the Utility replaced more than nearly 100,000 feet of underground cable, primarily in San Francisco and East Bay, replaced 100,686 feet of overhead wire, and installed or replaced 19 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 2014.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2009 to 2013 for electricity sold or delivered, including the classification of revenues by type of service.

	2013	2012	2011	2010	2009
Customers (average for the year)	5,243,216	5,214,170	5,188,638	5,155,724	5,137,240
Deliveries (in GWh) ⁽¹⁾	86,513	86,113	81,255	79,634	72,385
Revenues (in millions):					
Residential	\$ 5,091	\$ 4,953	\$ 4,778	\$ 4,795	\$ 4,759
Commercial	4,905	4,735	4,732	4,823	4,538
Industrial	1,388	1,408	1,379	1,424	1,392
Agricultural	1,021	901	692	736	770
Public street and highway lighting	75	79	77	79	74
Other	(128)	(11)	94	(1,178)	(1,700)
Subtotal	12,352	12,065	11,752	10,679	9,833
Regulatory balancing accounts	137	(51)	(151)	(35)	424
Total electricity operating revenues	\$ 12,489	\$ 12,014	\$ 11,601	\$ 10,644	\$ 10,257
Other Data:					
Average annual residential usage (kWh)	6,752	5,961	6,799	6,843	6,953
Average billed revenues (per kWh):					
Residential	\$ 0.1643	\$ 0.1594	\$ 0.1548	\$ 0.1560	\$ 0.1524
Commercial	0.1499	0.1449	0.1441	0.1468	0.1377
Industrial	0.0928	0.917	0.951	0.988	0.940
Agricultural	0.1454	0.1458	0.1475	0.1451	0.1327
Net plant investment per customer	\$ 6,002	\$ 4,919	\$ 5,045	\$ 4,728	\$ 4,336

⁽¹⁾ These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

Natural Gas Utility Operations

During 2013, the Utility continued to make significant progress on efforts to improve the safety and reliability of its natural gas operations, including performing extensive pipeline testing and monitoring, and replacing and upgrading equipment. Much of this work is part of the Utility's pipeline safety enhancement plan, approved by the CPUC in December 2012, to modernize and upgrade its natural gas transmission system to meet new, industry-wide safety standards. Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011 following their investigations into the San Bruno accident. The Utility has satisfied nine of the twelve NTSB recommendations. The Utility continues to make progress on the remaining three longer-term recommendations.

Since work began on the PSEP and other gas transmission work in 2011, the Utility has verified 657 miles of transmission pipeline through hydrostatic pressure tests or records verification, replaced 127 miles of transmission pipeline, installed 134 automated valves, and collected and digitized more than 3.5 million pipeline records. In July 2013, the Utility completed its search and review of records relating to pipeline pressure validation for all approximately 6,750 miles of its natural gas transmission system. (See the information within MD&A under the heading "Natural Gas Matters" in the 2013 Annual Report, which information is incorporated herein by reference.) In 2013, as part of the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, the Utility completed a "centerline" mapping survey of its entire gas transmission system to locate, mark, and map the center of all transmission pipelines. The Utility also continued to improve the integrity of transmission pipelines, which included retrofitting approximately 190 miles of pipeline in 2013 to accommodate in-line inspection tools.

The Utility has also implemented a new distribution integrity management program designed to enhance operations and improve the overall safety of the gas distribution system. The Utility has analyzed and replaced a total of 53 miles of Aldyl-A plastic pipeline in 2012 and 2013 and plans to replace 33 additional miles by the end of 2014. It also updated the geographic information system with information on approximately 5,600 miles of Aldyl-A pipeline, including additional pipeline and service attribute information. The Utility completed additional distribution leak surveys in 2013 (in addition to complying with regular distribution leak survey requirements) and repaired approximately 41,000 leaks of all grades.

In August 2013, the Utility opened its new 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. The Utility has continued to improve operations by utilizing modern tools and technologies to inspect pipelines, detect gas leaks, and provide real-time access to detailed maps of the Utility's underground gas system. The Utility has improved its supervisory controls and data acquisition system to better detect pipeline leaks and breaks and improve its integrity management program, including incorporating new analysis tools to identify and assess risks to pipeline integrity. The Utility has also implemented a system to enable employees and contractors to report potential pipeline integrity issues and track corrective actions taken. Finally, the Utility has significantly improved the speed at which it responds to gas odor calls.

Natural Gas System Assets

The Utility owns and operates an integrated natural gas transportation, storage, and distribution system that includes most of northern and central California. At December 31, 2013, the Utility's natural gas system consisted of approximately 42,559 miles of distribution pipelines, over 6,000 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations which receive, store and move natural 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. Line 300 interconnects with pipeline systems located in the U.S. Southwest and the Rocky Mountains that are owned by third parties (Transwestern Pipeline Company, El Paso Natural Gas Company, Questar Southern Trails Pipeline Company, and Kern River Pipeline Company). Line 300 has a receipt capacity of approximately 1.1 Bcf per day. Line 400 and 401 interconnect at the California-Oregon border with the pipeline systems owned by GTN and Ruby Pipeline, LLC. This line has a receipt capacity at the border of approximately 2.2 Bcf per day. Through interconnections with other interstate pipelines, 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 owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system and has a 25% interest in the new Gill Ranch Storage Field. These storage fields and the Utility's Gill Ranch share have a combined firm capacity of approximately 48.7 Bcf. In addition, three independent storage operators are interconnected to the Utility's northern California transportation system.

Natural Gas Services

The CPUC divides the Utility's on-system natural gas customers into two categories for the purpose of determining service reliability: core and non-core customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and small commercial natural gas customers. The non-core customer class is comprised of industrial, large commercial, and electric generation natural gas customers. In 2013, core customers represented more than 99% of the Utility's total natural gas customers and 37% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total natural gas customers and 63% of its total natural gas deliveries. In addition to deliveries discussed above, the Utility delivers gas to off-system customers (*i.e.* , outside of the Utility's service territory) and to third-party natural gas storage customers.

The Utility provides natural gas transportation services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas procurement service (*i.e.* , natural gas supply) from either the Utility or alternate energy service providers. 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 large non-core customers such as electricity generators, QF co-generators, enhanced oil recovery customers, refiners, and other large non-core customers. However, some smaller non-core customers are permitted to elect to receive core service, including procurement service, from the Utility if they agree to receive such service for a minimum of five years. Core service to non-core customers is subject to these restrictions to protect core procurement customers from price increases that could otherwise result if the Utility incurred costs to reinforce its pipeline system and take other measures to provide core service reliability on a short-term basis to serve new load from non-core customers.

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.

Natural Gas Supplies

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 2013, the Utility purchased approximately 240,414 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 13% of the total natural gas volume the Utility purchased during 2013.

Interstate and Canadian Natural Gas Transportation Services Agreements

The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. 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 GTN, 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 interconnect point with the Utility's natural gas system in the area of Daggett, CA.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2009 through 2013 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

	2013	2012	2011	2010	2009
Customers (average for the year)	4,378,797	4,353,278	4,327,407	4,295,741	4,271,007
Gas purchased (MMcf)	240,414	247,792	279,157	270,228	264,314
Average price of natural gas purchased	\$ 3.29	\$ 2.45	\$ 3.69	\$ 4.07	\$ 3.57
Bundled gas sales (MMcf):					
Residential	181,775	185,376	201,109	195,195	195,217
Commercial	46,668	47,341	52,230	53,921	57,550
Total	228,443	232,717	253,339	249,116	252,767
Revenues (in millions):					
Bundled gas sales:					
Residential	\$ 1,870	\$ 1,852	\$ 2,089	\$ 1,991	\$ 1,953
Commercial	395	383	464	474	496
Regulatory balancing accounts	240	221	295	305	289
Other	44	66	102	49	55
Bundled gas revenues	2,549	2,522	2,950	2,819	2,793
Transportation service only revenue	555	499	400	377	349
Operating revenues	\$ 3,104	\$ 3,021	\$ 3,350	\$ 3,196	\$ 3,142
Selected Statistics:					
Average annual residential usage (Mcf)	44	45	49	48	48
Average billed bundled gas sales revenues per Mcf:					
Residential	\$ 10.29	\$ 9.99	\$ 10.39	\$ 10.20	\$ 10.00
Commercial	8.47	8.09	8.89	8.79	8.62
Net plant investment per customer	\$ 2,234	\$ 1,696	\$ 1,721	\$ 1,637	\$ 1,557

Public Purpose and Customer Programs

California law has established various public purpose programs related to energy efficiency, energy research and development, and renewable energy resources. These programs include the CSI and other self-generation programs, as discussed under "Self-Generation Incentive Program and California Solar Initiative," below. California law requires the CPUC to authorize funding for these programs through the collection of rate surcharges and other rate components. Additionally, the CPUC has authorized funding for energy savings assistance and demand response programs. For 2013, the Utility was authorized revenue requirements of \$724 million from electric customers and \$160 million from gas customers to fund public purpose and other programs.

Energy Efficiency Programs

The Utility's energy efficiency programs are designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances, other energy-using equipment and energy management products to meet energy savings goals in California. The CPUC has authorized a total of \$823 million to fund the Utility's 2013 and 2014 energy efficiency programs, including programs administered by the Marin Energy Authority, a CCA, and a regional network of San Francisco Bay area cities and counties.

On December 20, 2012, the CPUC approved an energy efficiency incentive mechanism to reward the Utility and other California energy utilities for the successful implementation of their 2010-2012 energy efficiency programs. The mechanism provides each utility with an earnings rate composed of a 5% management fee based on qualified program expenditures and an additional performance bonus of up to 1%. The Utility's earnings rate for the 2010-2012 energy efficiency program cycle is 5.68%. The CPUC has awarded the Utility \$21 million and \$22 million for program years 2010 and 2011, respectively. The utilities will file their incentive claims based on the CPUC-audited 2012 program expenditures in the third quarter of 2014 for approval by the CPUC in the fourth quarter of 2014.

On September 5, 2013, the CPUC approved a new energy efficiency incentive mechanism designed to reward the Utility and the other California investor-owned utilities for the successful implementation of their energy efficiency portfolios for 2013 and beyond. The mechanism provides each utility with an ability to earn shareholder incentives through four separate earnings categories. The mechanism includes a cap on earnings for the Utility of approximately \$41 million annually for 2013 and 2014.

Demand Response Programs

Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. In April 2012, the CPUC authorized the Utility to collect \$192 million to fund its 2012-2014 demand response programs. On January 16, 2014, the CPUC approved a 2015 and 2016 bridge extension of the existing programs while it determines the enhanced role of demand response in meeting California's resource planning needs and operational requirements, with the exact amount of funding to be determined in a future CPUC decision. Pending a decision, funding will remain capped at the same level as the current 2013-2014 demand response budget.

Self-Generation Incentive Program and California Solar Initiative

The Utility administers the self-generation incentive program authorized by the CPUC to provide incentives to electricity and gas customers who install certain types of clean or renewable distributed generation and energy storage resources that meet all or a portion of their onsite energy usage. The CPUC approved annual funding for the self-generation incentive program of \$36 million through 2014, with any carryover funds to be administered through 2015. The Utility also administers the CSI in its service territory. The CPUC has authorized the Utility to collect approximately \$1.1 billion from 2007 through 2016 to fund customer incentives for the installation of retail solar energy projects to serve onsite load, as well as to fund research, development, and demonstration activities, and administration expenses. The current overall objective of this initiative is to install 3,000 MW (through both California investor-owned electric utilities and municipal electric utilities) through 2016. The California legislature approved additional funding of \$108 million for the low income CSI program and the CPUC will provide direction on this extension in 2014.

Low-Income Energy Efficiency Programs and California Alternate Rates for Energy

The CPUC has authorized the Utility to collect approximately \$469 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2012 through 2014. The Utility also provides a discount rate called the California Alternate Rates for Energy for low-income customers. This rate subsidy is paid for by the Utility's other customers. During any given year, the extent of the subsidy for customers collectively depends upon the number of customers participating in the program and their actual energy usage. In 2013, the amount of this subsidy was approximately \$833 million. The CPUC also authorized the Utility to recover approximately \$45 million in administrative costs relating to the California Alternate Rates for Energy subsidy through 2014.

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 discharge of pollutants into the air, water, and soil; the reporting and reduction of CO₂ and other GHG emissions; the remediation of hazardous and radioactive substances; 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. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify, or replace equipment, acquire permits and/or emission allowances or other emission credits for facility operations and clean-up, or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility's wastes may have been discharged. The actual amount of costs that the Utility will incur is subject to many factors, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility, the availability of recoveries or contributions from third parties, and the development of market-based strategies to address climate change. Generally, the Utility has recovered 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: Commitments and Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated by reference.

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, carbon monoxide, SO₂, NO_x, GHGs, and particulate matter.

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, including establishing an annual GHG reporting requirement. The Utility files annual GHG emission reports with the EPA covering its electric and gas operations in compliance with the EPA's reporting requirement. In addition, in January 2014, the EPA published draft regulations under section 111(b) of the Clean Air Act to control GHG emissions from new fossil fuel-fired power plants. While these draft regulations as presently written do not apply to the Utility's power plants currently in operation or under construction, it is possible that the final regulations may affect the design, construction, operation and cost of future fossil fuel-fired power plants. The EPA has also announced that it intends to issue draft regulations applicable to GHG emissions from existing power plants under section 111(d) of the Clean Air Act in June of 2014.

State Regulation. AB 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB established a state-wide GHG 1990 emissions baseline of 427 million metric tons of CO₂ (or its equivalent) to serve as the 2020 emissions limit for the state of California. 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 the major sources of GHG emissions.

The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next three-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB is allocating a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their electricity-related allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their electricity-related auction revenues among certain classes of their customers. Although the CPUC has previously authorized the utilities to recover their electricity related GHG compliance costs through rates, the recovery of these costs has been temporarily deferred until May 2014. In addition, the CARB may allocate a number of allowances for free to natural gas suppliers, including the Utility, for the benefit of the Utility's natural gas customers. In anticipation of the Utility's expanded compliance obligations for natural gas suppliers beginning January 1, 2015, the Utility has filed requests at the CPUC for authority to recover the natural gas supplier-related compliance costs from natural gas customers on an annual basis effective January 1, 2015. The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

Increasing use of renewable energy supplies also is expected to help reduce GHG emissions in California. (For more information, see "Renewable Generation Resources" above.)

Climate Change Mitigation and Adaptation Strategies. During 2013, 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 develop its strategy to plan for the actions that it will need to take to adapt to the likely impacts that climate change will have on the Utility's future operations. 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 and frequent hot weather events. Climate scientists also predict that climate change will result in significant reductions in snowpack in parts of the Sierra Nevada Mountains. This impact could, in turn, affect the Utility's hydroelectric generation. At this time, the Utility does not anticipate that reductions in Sierra Nevada snowpack will have a significant impact on its hydroelectric generation, due in large part to its adaptation strategies. For example, one adaptation strategy the Utility is developing is a combination of operating changes that may include, but are not limited to, higher winter carryover reservoir storage levels, reduced conveyance flows in canals and flumes in response to an increased portion of precipitation falling as rain rather than snow, and reduced discretionary reservoir water releases during the late spring and summer. If the Utility is not successful in fully adapting to projected reductions in snowpack over the coming decades, it may become necessary to replace some of its hydroelectric generation with electricity from other sources, including GHG-emitting natural gas-fired power plants.

With respect to natural gas operations, both safety-related pipeline hydrotesting/strength testing and normal pipeline maintenance and operations, releases the GHG methane to the atmosphere. The Utility has taken proactive steps to reduce the release of methane by implementing techniques including drafting and cross-compression which reduces the pressures and volumes 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. In 2013, the Utility implemented a proactive natural gas leak repair program, 40,676 gas leaks were identified, graded, prioritized and repaired. The primary reason for this effort was public safety, however, eliminating gas leaks results in a positive impact to the environment.

The Utility believes its strategies to reduce GHG emissions—such as energy efficiency and demand response programs, infrastructure improvements, and the support of renewable energy development—are also effective strategies for adapting to the expected increased demand for electricity in extreme hot weather events likely to result from climate change. PG&E Corporation and the Utility are also assessing the benefits and challenges associated with various climate change policies and identifying how a comprehensive program can be structured to mitigate overall costs to customers and the economy as a whole while ensuring that the environmental objectives of the program are met.

Emissions Data

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. As a result of the time necessary for a thorough, third-party verification of the Utility's GHG emissions, emissions data for 2012 are the most recent data available. The Utility reports its GHG emissions to the CARB. The Utility also voluntarily reports its GHG emissions to The Climate Registry, a non-profit organization that has a reporting and measurement standard applicable to most industry sectors across North America, which enables the Utility to publicly report GHG emissions not covered by mandatory reporting requirements. The Utility's third-party verified voluntary GHG inventory for 2012 totaled more than 57 million metric tonnes of CO₂-e, which includes approximately 38 million metric tonnes CO₂-e from customer natural gas use.

Beginning with its 2010 emissions, the Utility reports the GHG emissions from its facilities and operations to the EPA under its mandatory reporting requirements. PG&E Corporation and the Utility also publish third-party-verified GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

2012 Emissions Reported to the California Air Resources Board

The following table shows the GHG emissions data the Utility reported to the CARB under AB 32.

Source	Amount (metric tonnes CO ₂ – equivalent)
Fossil Fuel-Fired Plants ⁽¹⁾	2,466,851
Natural Gas Compressor Stations ⁽²⁾	351,878
Distribution Fugitive Natural Gas Emissions	222,995
Customer Natural Gas Use ⁽³⁾	42,434,940
Total	45,476,664

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations; does not include de minimis emissions.

(2) Includes compressor stations emitting more than 25,000 metric tonnes of CO₂-e annually; does not include de minimis emissions.

(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of gas delivered to other natural distribution companies. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value fuel that is delivered to covered entities as calculated by the CARB.

Benchmarking GHG Emissions for Delivered Electricity

The Utility's third-party-verified CO₂ emissions rate associated with the electricity delivered to customers in 2012 was 445 pounds of CO₂ per MWh. The Utility's 2012 emissions rate as compared to the national and California averages for electric utilities is shown in the following table:

	Amount (Pounds of CO ₂ per MWh)
U.S. Average ⁽¹⁾	1,216
California's Average ⁽¹⁾	659
Pacific Gas and Electric Company ⁽²⁾	445

(1) Source: Environmental Protection Agency eGRID 2012 Version 1.0, which contains year 2009 information configured to reflect the electric power industry's current structure as of May 10, 2012. This is the most up-to-date information available from EPA.

(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 total emissions and the Utility's emission rate for delivered electricity.

Emissions Data for Utility-Owned Generation

In addition to GHG emissions data provided above, the table below sets forth information about the GHG and other emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised more than 40% of the Utility's delivered electricity in 2012. The Utility's fossil fuel-fired generation comprised approximately 8% of the Utility's delivered electricity in 2012.

	2012	2011
Total NOx Emissions (tons)	158	144
NOx Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.05	0.06
All Plants	0.01	0.008
Total SO2 Emissions (tons)	15	12
SO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.005	0.005
All Plants	0.0009	0.0007
Total CO2 Emissions (metric tons)	2,464,464	2,024,206
CO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	864	875
All Plants	172	126
Other Emissions Statistics		
Sulfur Hexafluoride Emissions		
Total Sulfur Hexafluoride Emissions (metric tons CO2-e)	63,127	70,052
Sulfur Hexafluoride Emissions Leak Rate	1.5%	1.7%

Water Quality

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations.

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 nuclear power plants, including Diablo Canyon. The committee's consultant is expected to submit a final report to the California Water Board in 2014. 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.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements issued by the EPA under the federal Resource Conservation and Recovery Act and the CERCLA, as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site, and in some cases corporate successors to the operators or arrangers. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources, and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of hazardous substances and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility has a comprehensive program in place to comply with federal, state, and local laws and regulations related to hazardous materials and hazardous waste compliance, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the California Department of Toxic Substances Control, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include 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. 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. 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. For more information about environmental remediation liabilities, see the sections within MD&A entitled "Environmental Matters," "Critical Accounting Policies," and Note 14: Commitments and Contingencies—Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

Generation Facilities

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal and fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies. Fossil fuel-fired Units 1 and 2 of the Utility's Humboldt Bay power plant shut down in September 2010, and are now in the decommissioning process along with the nuclear Unit 3, which was shut down in 1976. The Utility has entered into a voluntary cleanup agreement with the California Department of Toxic Substances Control and is currently completing a soil and groundwater investigation to determine what soil and groundwater remediation may be necessary.

Former Manufactured Gas Plant Sites

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain retired MGP sites. During their operation, from the mid-1800s through the early 1900s, MGPs produced lampblack and coal tar residues. The residues from these operations, which may remain at some sites, contain chemical compounds that now are classified as hazardous. The Utility has been coordinating with environmental agencies and third-party owners to evaluate and take appropriate action to mitigate any potential environmental concerns at 41 MGP sites that the Utility owned or operated in the past.

Natural Gas Compressor Stations

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. The Utility has incurred significant environmental liabilities associated with these sites. For more information about the Utility's remediation and abatement efforts and related liabilities, see Note 14: Commitments and Contingencies—Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

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. 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 Unit 3. As a result, the Utility constructed an interim dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024, and a separate facility at Humboldt Bay. 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.

On September 5, 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. In 2013, the Utility was awarded an additional \$29 million for costs incurred between January 2011 and May 2012. These proceeds were recorded in a regulatory balancing account and are being refunded to customers through rates. On January 31, 2014, the U.S. Department of Justice and the Utility executed an addendum extending the term of the settlement agreement for an additional three years, through 2016. The amended settlement agreement does not address costs incurred for spent fuel storage after 2016 and such costs could be the 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.

Nuclear Decommissioning

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Humboldt Bay Unit 3. 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. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennial Proceeding in the section of MD&A entitled "Regulatory Matters–Diablo Canyon Nuclear Power Plant" and Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.)

Endangered Species

Many of the Utility's facilities and operations are located in, or pass through, areas that are designated as critical habitats for federal, or state-listed endangered, threatened, or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated at or near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

ITEM 1A. Risk Factors

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility appears within MD&A under the heading "Risk Factors" in the 2013 Annual Report, which information is incorporated herein by reference.

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 above under "Electric Utility Operations" and "Natural Gas Utility Operations" which information is incorporated herein by reference. 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 11.0 million square feet of real property, including 8.6 million square feet that the Utility owns. 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 has entered into leases for approximately 87,000 square feet of office space in San Francisco, California. Leases for 40,000 square feet will expire in 2014 and the remaining leases will expire in 2022.

The Utility currently owns approximately 170,000 acres of land, including approximately 140,000 acres of watershed lands. Pursuant to its 2002 Settlement Agreement with the CPUC, 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 through its Land Conservation Commitment. The Utility will not donate watershed lands that contain the Utility’s or a joint licensee’s hydroelectric generation facilities, but this land will be encumbered with conservation easements. Pursuant to the 2002 Settlement Agreement, the Pacific Forest Watershed Lands Stewardship Council was formed to oversee the development and implementation of a Land Conservation Plan that articulates the long-term management objectives for these watershed lands. The Council is governed by an 18-member board of directors, one of whom is appointed by the Utility. The other members represent a range of diverse stakeholders in the watershed lands. The Utility’s goal is to implement all the Land Conservation Commitment transactions by the end of 2017, subject to securing all required regulatory approvals.

ITEM 3. Legal Proceedings

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation’s and the Utility’s liability for legal matters, see Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

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 EPA published draft regulations in April 2011 to implement the requirements of SECTION 316(b) of the federal Clean Water Act that requires 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. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations. As part of the implementation process for the California Water Resources Control Board’s once-through cooling policy, the California Water Board’s nuclear review committee is overseeing development of an alternative technology assessment for Diablo Canyon. The committee’s consultant is expected to submit its final report to the California Water Board in 2014. The California Water Board’s policy on once-through cooling and the EPA’s final regulations could affect future negotiations between the Central Coast Board and the Utility regarding the status of the 2003 settlement agreement. (See “Item 1. Business–Environmental Matters–Water Quality” above.) PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material impact on their Utility’s financial condition or results of operations.

Litigation Related to the San Bruno Accident and Natural Gas Spending

Following the San Bruno accident various lawsuits were filed in San Mateo County Superior Court against PG&E Corporation and the Utility to seek compensation for personal injury and property damage, and other relief, including punitive damages. In 2011 and 2012, the Utility entered into settlement agreements to resolve many of the claims and In September 2013, the Utility agreed to settle the claims of substantially all of the remaining plaintiffs who sought compensation. At December 31, 2013, the Utility has recorded cumulative charges of \$565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident and has made cumulative payments of \$520 million to third-party claimants.

At December 31, 2013, there were also four 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 have filed a consolidated complaint with the San Mateo County Superior Court. The court has lifted the stay on these proceedings for the limited purpose of allowing the parties to exchange information and discuss possible resolution. A case management conference is scheduled for April 18, 2014. The remaining purported shareholder derivative lawsuit, 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 these derivative lawsuits will be resolved.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than \$100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. PG&E Corporation and the Utility contest the allegations.

For additional information, see the discussion within MD&A under the heading, “Natural Gas Matters” and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements contained in the 2013 Annual Report, which discussions are incorporated herein by reference.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility related to the Utility’s natural gas operations and the San Bruno accident. Evidentiary hearings and briefing on the issue of alleged violations have been completed in each of these investigations. The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of \$2.25 billion on the Utility, consisting of a \$300 million fine payable to the State General Fund and \$1.950 billion of non-recoverable costs to perform work under the Utility’s pipeline safety enhancement plan and to implement the operational remedies. Several other parties have also submitted penalty recommendations. The administrative law judges who oversee the investigation are expected to issue one or more presiding officers’ decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued.

For more information, see discussions within MD&A under the heading, “Natural Gas Matters,” and Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

Other CPUC Enforcement Matters

The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility’s operations or otherwise. In January 2012, the SED imposed fines of \$16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from \$50,000 to \$8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as “errata” to correct information about some segments in Lines 101 and 147 (two of the Utility’s natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately \$14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. On January 23, 2014, the Utility filed an application for rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility’s gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility’s natural gas system records are reliable.

In addition, the Utility has notified the CPUC and the SED that the Utility is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments from pipeline rights-of-way over a multi-year period. The SED could impose penalties on the Utility or take other enforcement action in connection with this matter.

Criminal Investigation

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. A criminal charge or finding would further harm the Utility's reputation. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

See the discussions within MD&A under the heading "Natural Gas Matters – Criminal Investigation," and in Note 14: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which discussions are incorporated herein by reference.

ITEM 4. Mine Safety Disclosures

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of PG&E Corporation “executive officers,” as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows.

Name	Age	Position
Anthony F. Earley, Jr.	64	Chairman of the Board, Chief Executive Officer, and President
Kent M. Harvey	55	Senior Vice President and Chief Financial Officer
Christopher P. Johns	53	President, Pacific Gas and Electric Company
Hyun Park	52	Senior Vice President and General Counsel
Greg S. Pruett	56	Senior Vice President, Corporate Affairs
John R. Simon	49	Senior Vice President, Human Resources

All officers of PG&E Corporation serve at the pleasure of the Board of Directors of PG&E Corporation. During at least the past five years through February 3, 2014, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

Name	Position	Period Held Office
Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President Executive Chairman of the Board, DTE Energy Company Chairman of the Board and Chief Executive Officer, DTE Energy Company	September 13, 2011 to present October 1, 2010 to September 12, 2011 August 1998 to September 30, 2010
Kent M. Harvey	Senior Vice President and Chief Financial Officer Senior Vice President, Financial Services, Pacific Gas and Electric Company Senior Vice President and Chief Risk and Audit Officer	August 1, 2009 to present August 1, 2009 to present October 1, 2005 to July 31, 2009
Christopher P. Johns	President, Pacific Gas and Electric Company Senior Vice President and Chief Financial Officer Senior Vice President, Financial Services, Pacific Gas and Electric Company Senior Vice President, Chief Financial Officer, and Treasurer Senior Vice President and Treasurer, Pacific Gas and Electric Company	August 1, 2009 to present May 1, 2009 to July 31, 2009 May 1, 2009 to July 31, 2009 October 4, 2005 to April 30, 2009 June 1, 2007 to April 30, 2009
Hyun Park	Senior Vice President and General Counsel	November 13, 2006 to present
Greg S. Pruett	Senior Vice President, Corporate Affairs Senior Vice President, Corporate Affairs, Pacific Gas and Electric Company Senior Vice President, Corporate Relations Senior Vice President, Corporate Relations, Pacific Gas and Electric Company	November 1, 2009 to present November 1, 2009 to present November 1, 2007 to October 31, 2009 March 1, 2009 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources Senior Vice President, Human Resources, Pacific Gas and Electric Company	April 16, 2007 to present April 16, 2007 to present

The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at February 3, 2014 were as follows:

Name	Age	Position
Anthony F. Earley, Jr.	64	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation
Christopher P. Johns	53	President
Nickolas Stavropoulos	55	Executive Vice President, Gas Operations
Geisha J. Williams	52	Executive Vice President, Electric Operations
Karen A. Austin	52	Senior Vice President and Chief Information Officer
Desmond A. Bell	51	Senior Vice President, Safety and Shared Services
Thomas E. Bortorff	60	Senior Vice President, Regulatory Affairs
Helen A. Burt	57	Senior Vice President and Chief Customer Officer
John T. Conway	56	Senior Vice President, Energy Supply
Edward D. Halpin	52	Senior Vice President and Chief Nuclear Officer
Kent M. Harvey	55	Senior Vice President, Financial Services
Gregory K. Kiraly	49	Senior Vice President, Electric Distribution Operations
Hyun Park	52	Senior Vice President and General Counsel, PG&E Corporation
Greg S. Pruett	56	Senior Vice President, Corporate Affairs
John R. Simon	49	Senior Vice President, Human Resources
Jesus Soto, Jr.	46	Senior Vice President, Engineering, Construction & Operations
Fong Wan	52	Senior Vice President, Energy Procurement
Dinyar B. Mistry	51	Vice President, Chief Financial Officer, and Controller

All officers of the Utility serve at the pleasure of the Board of Directors of the Utility. During at least the past five years through February 3, 2014, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

Name	Position	Period Held Office
Anthony F. Earley, Jr.	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	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
	Senior Vice President and Treasurer	June 1, 2007 to April 30, 2009
	Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation	October 4, 2005 to April 30, 2009
Nickolas Stavropoulos	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	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	Senior Vice President and Chief Information Officer	June 1, 2011 to present
	President, Consumer Electronics, Sears Holdings	February 2009 to May 2011
	Executive Vice President, Chief Information Officer, Sears Holdings	March 2005 to January 2009

Desmond A. Bell	Senior Vice President, Safety and Shared Services Senior Vice President, Shared Services and Chief Procurement Officer Vice President, Shared Services and Chief Procurement Officer	January 1, 2012 to present October 1, 2008 to December 31, 2011 March 1, 2008 to September 30, 2008
Thomas E. Bottorff	Senior Vice President, Regulatory Affairs Senior Vice President, Regulatory Relations	September 1, 2012 to present October 14, 2005 to August 31, 2012
Helen A. Burt	Senior Vice President and Chief Customer Officer	February 27, 2006 to present
John T. Conway	Senior Vice President, Energy Supply Senior Vice President, Energy Supply and Chief Nuclear Officer Senior Vice President, Generation and Chief Nuclear Officer Senior Vice President and Chief Nuclear Officer	March 1, 2012 to present April 1, 2009 to February 29, 2012 October 1, 2008 to March 31, 2009 March 1, 2008 to September 30, 2008
Edward D. Halpin	Senior Vice President and Chief Nuclear Officer President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company Chief Nuclear Officer, South Texas Project Nuclear Operating Company	April 2, 2012 to present December 2009 to March 2012 October 2008 to November 2009
Kent M. Harvey	Senior Vice President, Financial Services Senior Vice President and Chief Financial Officer, PG&E Corporation Senior Vice President and Chief Risk and Audit Officer, PG&E Corporation	August 1, 2009 to present August 1, 2009 to present October 1, 2005 to July 31, 2009
Gregory K. Kiraly	Senior Vice President, Electric Distribution Operations Vice President, Electric Distribution Operations Vice President, SmartMeter Operations Vice President, Electric Maintenance and Construction Vice President, Transmission Substations, Maintenance and Construction	September 18, 2012 to present October 1, 2011 to September 17, 2012 August 23, 2010 to September 30, 2011 January 1, 2010 to August 22, 2010 January 1, 2009 to December 31, 2009
Hyun Park	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
Greg S. Pruett	Senior Vice President, Corporate Affairs Senior Vice President, Corporate Affairs, PG&E Corporation Senior Vice President, Corporate Relations Senior Vice President, Corporate Relations, PG&E Corporation	November 1, 2009 to present November 1, 2009 to present March 1, 2009 to October 31, 2009 November 1, 2007 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to present April 16, 2007 to present
Jesus Soto, Jr.	Senior Vice President, Engineering, Construction & Operations Senior Vice President, Gas Transmission Operations Vice President, Operations Services, El Paso Pipeline Group	September 2013 to present May 29, 2012 to September 2013 May 2007 to May 2012
Fong Wan	Senior Vice President, Energy Procurement	October 1, 2008 to present
Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller Vice President and Controller, PG&E Corporation Vice President and Controller Vice President and Chief Risk and Audit Officer Vice President and Chief Risk and Audit Officer, PG&E Corporation Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation	October 1, 2011 to present March 8, 2010 to present March 8, 2010 to September 30, 2011 September 16, 2009 to March 7, 2010 August 1, 2009 to March 7, 2010 January 1, 2009 to July 31, 2009

PART II

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

As of February 3, 2014, there were 64,972 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and the Swiss 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 under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2013 Annual Report, which information is incorporated herein by reference. Shares of common stock of the Utility are solely owned by PG&E Corporation. Information about the frequency, amount, and restrictions upon the payment of, dividends on common stock declared by PG&E Corporation and the Utility is set forth in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, Note 5: Common Stock and Share-Based Compensation—Dividends of the Notes to the Consolidated Financial Statements, and within MD&A under the heading "Liquidity and Financial Resources—Dividends," in the 2013 Annual Report, which information is incorporated herein by reference.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation made equity contributions totaling \$305 million to the Utility in order to maintain the Utility's 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures. PG&E Corporation did not make any sales of unregistered equity securities during 2013.

Issuer Purchases of Equity Securities

During the quarter ended December 31, 2013, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. Also, during the quarter ended December 31, 2013, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 6. Selected Financial Data

Selected financial information, for each of PG&E Corporation and the Utility for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

A discussion of PG&E Corporation's and the Utility's consolidated financial condition and results of operations is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" as well as the "Glossary" in the 2013 Annual Report, which discussion is incorporated herein by reference.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A is set forth within MD&A under the heading "Risk Management Activities," and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 8. Financial Statements and Supplementary Data

Information responding to Item 8 is set forth under the following headings for PG&E Corporation: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity" in the 2013 Annual Report and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," and "Reports of Independent Registered Public Accounting Firm" in the 2013 Annual Report, which information is incorporated herein by reference.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

ITEM 9A. Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2013, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the 1934 Act is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the 1934 Act is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2013 Annual Report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," which information is incorporated by reference and included in Exhibit 13 to this report.

ITE M 9B. Other Information

Not applicable.

PART III

ITEM 10 . Directors, Executive Officers and Corporate Governance

Information regarding executive officers of PG&E Corporation and the Utility is set forth under “Executive Officers of the Registrants” at the end of Part I of this report. Other information regarding directors is set forth under the heading “Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act is included under the heading “Section 16(a) Beneficial Ownership Reporting Compliance” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Website Availability of Code of Ethics, Corporate Governance and Other Documents

The following documents are available both on PG&E Corporation's website www.pgecorp.com, and the Utility's website, www.pge.com : (1) the codes of conduct and ethics adopted by PG&E Corporation and the Utility applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and the Utility that apply to their respective Chief Executive Officers, Chief Financial Officers, or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within four business days of the waiver.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

During 2013 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

Audit Committees and Audit Committee Financial Expert

Information regarding the Audit Committees of PG&E Corporation and the Utility and the “audit committee financial expert” as defined by the SEC is set forth under the headings “Corporate Governance – Board Committee Duties – Audit Committees” and “Corporate Governance – Committee Membership” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 11 . Executive Compensation

Information responding to Item 11, for each of PG&E Corporation and the Utility, is set forth under the headings “Compensation Discussion and Analysis,” “Compensation Committee Report,” “Summary Compensation Table - 2013,” “Grants of Plan-Based Awards in 2013,” “Outstanding Equity Awards at Fiscal Year End - 2013,” “Option Exercises and Stock Vested During 2013,” “Pension Benefits – 2013,” “Non-Qualified Deferred Compensation – 2013,” “Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability” and “Compensation of Non-Employee Directors – 2013 Director Compensation” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information regarding the beneficial ownership of securities for each of PG&E Corporation and the Utility is set forth under the headings “Share Ownership Information – Security Ownership of Management” and “Share Ownership Information – Principal Shareholders” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2013 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by shareholders	6,194,819 ⁽¹⁾	\$ 32.98	3,310,474 ⁽²⁾
Equity compensation plans not approved by shareholders	-	-	-
Total equity compensation plans	6,194,819 ⁽¹⁾	\$ 32.98	3,310,474 ⁽²⁾

(1) Includes 46,185 phantom stock units, 2,329,256 restricted stock units and 3,566,966 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For a description of these performance shares, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which description is incorporated herein by reference. For performance shares, amounts reflected in this table assume payout in shares at 200% of target. The actual number of shares issued can range from 0% to 200% of target depending on achievement of total shareholder return objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issuing the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance.

(2) Represents the total number of shares available for issuance under the LTIP and the 2006 LTIP as of December 31, 2013. Outstanding stock-based awards granted under the LTIP include stock options, and phantom stock. The LTIP expired on December 31, 2005. The 2006 LTIP, which became effective on January 1, 2006, authorizes up to 12 million shares to be issued pursuant to awards granted under the 2006 LTIP. Outstanding stock-based awards granted under the 2006 LTIP include stock options, restricted stock, restricted stock units, phantom stock and performance shares. For a description of the 2006 LTIP, see Note 5: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2013 Annual Report, which description is incorporated herein by reference.

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

Information responding to Item 13, for each of PG&E Corporation and the Utility, is included under the headings “Related Party Transactions” and “Corporate Governance – Board and Director Independence and Qualifications” and “Corporate Governance – Committee Membership” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

Information responding to Item 14, for each of PG&E Corporation and the Utility, is set forth under the heading “Information Regarding the Independent Registered Public Accounting Firm for PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2014 Annual Meetings of Shareholders, which information is incorporated herein by reference.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this report:

1. The following consolidated financial statements, supplemental information and reports of independent registered public accounting firm are contained in the 2013 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2013 and 2012 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012, and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2013, 2012, and 2011 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2013, 2012, and 2011 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules and report of independent registered public accounting firm are filed as part of this report:

Reports of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

I—Condensed Financial Information of Parent as of December 31, 2013 and 2012 and for the Years Ended December 31, 2013, 2012, and 2011.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2013, 2012, and 2011.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

3. Exhibits required by Item 601 of Regulation S-K

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1)
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2)
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture dated as of March 13, 2007 relating to the Utility's issuance of \$700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.3	Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility's issuance of \$500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.4	Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility's issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1)
4.5	Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of \$600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)

4.6	Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of \$400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and \$200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1)
4.7	Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)
4.8	Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1)
4.9	Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1)
4.10	Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1)
4.11	Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1)
4.12	Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)
4.13	Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)
4.14	Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
4.15	Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.16	Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and \$350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)

4.17	Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of \$375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and \$375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)
4.18	Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and \$500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)
4.19	Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1)
4.20	First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of \$350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2)
10.1	Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.2	Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2)
10.3	Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.5		Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
10.6	*	Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.7	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5)
10.8	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3)
10.9	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2)
10.10	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3)
10.11	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6)
10.12	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4)
10.13	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.14	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5)
10.15	*	Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.16	*	Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18)
10.17	*	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18)
10.18	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2)

10.19	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21)
10.20	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7)
10.21	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8)
10.22	*	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)
10.23	*	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.24	*	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24)
10.25	*	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
10.26	*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27)
10.27	*	Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27)
10.28	*	Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28)
10.29	*	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31)
10.30	*	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2)
10.31	*	Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30)
10.32	*	Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7)

10.33	*	PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)
10.34	*	Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36)
10.35	*	Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37)
10.36	*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40)
10.37	*	PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
10.38	*	Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3)
10.39	*	Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1)
10.40	*	Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1)
10.41	*	Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2)
10.42	*	Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2)
10.43	*	Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.44	*	Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3)
10.45	*	Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1)
10.46	*	Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4)

10.47	*	Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2)
10.48	*	Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2)
10.49	*	Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3)
10.50	*	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3)
10.51	*	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2)
10.52	*	PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6)
10.53	*	PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5)
10.54	*	PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51)
10.55	*	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
10.56	*	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58)
10.57	*	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
10.58	*	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
10.59	*	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54)
10.60	*	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
10.61	*	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
12.1		Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company

12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
13	The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Glossary," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," and "Report of Independent Registered Public Accounting Firm."
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2013 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION
(Registrant)

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)

ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.

By:

Chairman of the Board, Chief Executive Officer, and President

Date: February 11, 2014

CHRISTOPHER P. JOHNS

Christopher P. Johns

By:

President

Date: February 11, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
A. Principal Executive Officers		
<u>ANTHONY F. EARLEY, JR.</u> Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation)	February 11, 2014
<u>CHRISTOPHER P. JOHNS</u> Christopher P. Johns	President (Pacific Gas and Electric Company)	February 11, 2014
B. Principal Financial Officers		
<u>KENT M. HARVEY</u> Kent M. Harvey	Senior Vice President and Chief Financial Officer (PG&E Corporation)	February 11, 2014
<u>DINYAR B. MISTRY</u> Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2014
C. Principal Accounting Officer		
<u>DINYAR B. MISTRY</u> Dinyar B. Mistry	Vice President and Controller (PG&E Corporation) Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 11, 2014
D. Directors		
<u>*LEWIS CHEW</u> Lewis Chew	Director	February 11, 2014

<u>*C. LEE COX</u> C. Lee Cox	Director	February 11, 2014
<u>*ANTHONY F. EARLEY, JR.</u> Anthony F. Earley, Jr.	Director	February 11, 2014
<u>*FRED J. FOWLER</u> Fred J. Fowler	Director	February 11, 2014
<u>*MARYELLEN C. HERRINGER</u> Maryellen C. Herringer	Director	February 11, 2014
<u>*CHRISTOPHER P. JOHNS</u> Christopher P. Johns	Director (Pacific Gas and Electric Company only)	February 11, 2014
<u>*RICHARD C. KELLY</u>	Director	February 11, 2014
<u>*ROGER H. KIMMEL</u> Roger H. Kimmel	Director	February 11, 2014
<u>*RICHARD A. MESERVE</u> Richard A. Meserve	Director	February 11, 2014
<u>*FORREST E. MILLER</u> Forrest E. Miller	Director	February 11, 2014
<u>*ROSENDO G. PARRA</u> Rosendo G. Parra	Director	February 11, 2014
<u>*BARBARA L. RAMBO</u> Barbara L. Rambo	Director	February 11, 2014
<u>*BARRY LAWSON WILLIAMS</u> Barry Lawson Williams	Director	February 11, 2014
*By: <u>HYUN PARK</u> HYUN PARK, Attorney-in-Fact		

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the “Company”) and Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, and the Company's and the Utility's internal control over financial reporting as of December 31, 2013, and have issued our reports thereon dated February 11, 2014 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties); such consolidated financial statements and reports are included in your 2013 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and Utility listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 11, 2014

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT
CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(in millions, except per share amounts)

	Year Ended December 31,		
	2013	2012	2011
Administrative service revenue	\$ 41	\$ 43	\$ 44
Operating expenses	(42)	(41)	(44)
Interest income	1	1	1
Interest expense	(25)	(22)	(22)
Other income	(57)	(39)	(17)
Equity in earnings of subsidiaries	848	817	852
Income before income taxes	766	759	814
Income tax benefit	48	57	30
Net income	<u>\$ 814</u>	<u>\$ 816</u>	<u>\$ 844</u>
Other Comprehensive Income			
Pension and other postretirement benefit plans (net of taxes of \$80, \$72, \$9, at respective dates)	113	108	(11)
Other (net of taxes of \$26, \$3, and \$0, at respective dates)	38	4	-
Total other comprehensive income (loss)	<u>151</u>	<u>112</u>	<u>(11)</u>
Comprehensive Income	<u>\$ 965</u>	<u>\$ 928</u>	<u>\$ 833</u>
Weighted average common shares outstanding, basic	<u>444</u>	<u>424</u>	<u>401</u>
Weighted average common shares outstanding, diluted	<u>445</u>	<u>425</u>	<u>402</u>
Net earnings per common share, basic	<u>\$ 1.83</u>	<u>\$ 1.92</u>	<u>\$ 2.10</u>
Net earnings per common share, diluted	<u>\$ 1.83</u>	<u>\$ 1.92</u>	<u>\$ 2.10</u>

PG&E CORPORATION
SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 231	\$ 207
Advances to affiliates	30	26
Income taxes receivable	13	33
Other current assets	86	-
Total current assets	360	266
Noncurrent Assets		
Equipment	2	1
Accumulated depreciation	(1)	(1)
Net equipment	1	-
Investments in subsidiaries	14,711	13,387
Other investments	110	102
Income taxes receivable	5	5
Deferred income taxes	188	178
Other	-	1
Total noncurrent assets	15,015	13,673
Total Assets	\$ 15,375	\$ 13,939
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 260	\$ 120
Long-term debt, classified as current	350	-
Accounts payable – other	66	48
Other	230	221
Total current liabilities	906	389
Noncurrent Liabilities		
Long-term debt	-	349
Other	127	127
Total noncurrent liabilities	127	476
Common Shareholders' Equity		
Common stock	9,550	8,428
Reinvested earnings	4,742	4,747
Accumulated other comprehensive income (loss)	50	(101)
Total common shareholders' equity	14,342	13,074
Total Liabilities and Shareholders' Equity	\$ 15,375	\$ 13,939

PG&E CORPORATION
SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
CONDENSED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2013	2012	2011
Cash Flows from Operating Activities:			
Net income	\$ 814	\$ 816	\$ 844
Adjustments to reconcile net income to net cash provided by operating activities:			
Stock-based compensation amortization	54	51	36
Equity in earnings of subsidiaries	(848)	(817)	(852)
Deferred income taxes and tax credits, net	(10)	(31)	(26)
Noncurrent income taxes receivable/payable	-	(6)	(47)
Current income taxes receivable/payable	20	(82)	49
Other	(20)	20	(80)
Net cash provided by (used in) operating activities	10	(49)	(76)
Cash Flows From Investing Activities:			
Investment in subsidiaries	(1,371)	(1,023)	(759)
Dividends received from subsidiaries ⁽¹⁾	716	716	716
Proceeds from tax equity investments	275	228	129
Other	(8)	-	-
Net cash provided by (used in) investing activities	(388)	(79)	86
Cash Flows From Financing Activities:			
Borrowings under revolving credit facilities	140	120	150
Repayments under revolving credit facilities	-	-	(150)
Common stock issued	1,045	751	662
Common stock dividends paid ⁽²⁾	(782)	(746)	(704)
Other	(1)	1	1
Net cash provided by (used in) financing activities	402	126	(41)
Net change in cash and cash equivalents	24	(2)	(31)
Cash and cash equivalents at January 1	207	209	240
Cash and cash equivalents at December 31	\$ 231	\$ 207	\$ 209
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	\$ (23)	\$ (20)	\$ (20)
Income taxes, net	21	(60)	8
Supplemental disclosures of noncash investing and financing activities			
Noncash common stock issuances	\$ 22	\$ 22	\$ 24
Common stock dividends declared but not yet paid	208	196	188

⁽¹⁾ Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries an investing cash flow.

⁽²⁾ On January 15, April 15, July 15, October 15, 2013, PG&E Corporation paid quarterly common stock dividends of \$0.455 per share.

On January 15, April 15, July 15, October 15, 2012, PG&E Corporation paid quarterly common stock dividends of \$0.455 per share.

On January 15, April 15, July 15, October 15, 2011, PG&E Corporation paid quarterly common stock dividends of \$0.455 per share.

PG&E Corporation

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2013, 2012, and 2011
(in millions)

Description	Balance at Beginning of Period	Additions		Deductions ⁽²⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
Valuation and qualifying accounts deducted from assets:					
2013:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 87	\$ 53	\$ -	\$ 60	\$ 80
2012:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 81	\$ 66	\$ -	\$ 60	\$ 87
2011:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 81	\$ 60	\$ -	\$ 60	\$ 81

⁽¹⁾ Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

⁽²⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

Pacific Gas and Electric Company

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2013, 2012, and 2011
(in millions)

Description	Balance at Beginning of Period	Additions		Deductions ⁽²⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
Valuation and qualifying accounts deducted from assets:					
2013:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 87	\$ 53	\$ -	\$ 60	\$ 80
2012:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 81	\$ 66	\$ -	\$ 60	\$ 87
2011:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 81	\$ 60	\$ -	\$ 60	\$ 81

⁽¹⁾ Allowance for uncollectible accounts is deducted from “Accounts receivable – Customers.”

⁽²⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of June 19, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 3.1)
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.5	Bylaws of Pacific Gas and Electric Company amended as of June 19, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 3.2)
4.1	Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust Company, N.A. (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture dated as of March 13, 2007 relating to the Utility's issuance of \$700,000,000 principal amount of 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.3	Second Supplemental Indenture dated as of December 4, 2007 relating to the Utility's issuance of \$500,000,000 principal amount of 5.625% Senior Notes due November 30, 2017 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1)
4.4	Third Supplemental Indenture dated as of March 3, 2008 relating to the Utility's issuance of 5.625% Senior Notes due November 30, 2017 and 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 3, 2008 (File No. 1-2348), Exhibit 4.1)
4.5	Fourth Supplemental Indenture dated as of October 21, 2008 relating to the Utility's issuance of \$600,000,000 aggregate principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)

4.6	Fifth Supplemental Indenture dated as of November 18, 2008 relating to the Utility's issuance of \$400,000,000 aggregate principal amount of its 6.25% Senior Notes due December 1, 2013 and \$200 million principal amount of its 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1)
4.7	Sixth Supplemental Indenture, dated as of March 6, 2009 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1)
4.8	Eighth Supplemental Indenture dated as of November 18, 2009 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1)
4.9	Ninth Supplemental Indenture dated as of April 1, 2010 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due January 15, 2040 and \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1, 2010 (File No. 1-2348), Exhibit 4.1)
4.10	Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1)
4.11	Twelfth Supplemental Indenture dated as of November 18, 2010 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1)
4.12	Thirteenth Supplemental Indenture dated as of May 13, 2011, relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1)
4.13	Fourteenth Supplemental Indenture dated as of September 12, 2011 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1)
4.14	Sixteenth Supplemental Indenture dated as of December 1, 2011 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1)
4.15	Seventeenth Supplemental Indenture dated as of April 16, 2012 relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1)
4.16	Eighteenth Supplemental Indenture dated as of August 16, 2012 relating to the issuance of \$400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and \$350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due August 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1)

4.17	Nineteenth Supplemental Indenture dated as of June 14, 2013 relating to the issuance of \$375,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and \$375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No. 1-2348), Exhibit 4.1)
4.18	Twentieth Supplemental Indenture dated as of November 12, 2013 relating to the issuance of \$300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and \$500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1)
4.19	Senior Note Indenture related to PG&E Corporation's 5.75% Senior Notes due April 1, 2014, dated as of March 12, 2009, between PG&E Corporation and Deutsche Bank Trust Company Americas as Trustee (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.1)
4.20	First Supplemental Indenture, dated as of March 12, 2009 relating to the issuance of \$350,000,000 aggregate principal amount of PG&E Corporation's 5.75% Senior Notes due April 1, 2014 (incorporated by reference to PG&E Corporation's Form 8-K dated March 10, 2009 (File No. 1-12609), Exhibit 4.2)
10.1	Amended and restated credit agreement dated April 1, 2013 among (1) PG&E Corporation as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) J.P. Morgan Securities LLC, Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.2	Amended and restated credit agreement dated April 1, 2013 among (1) Pacific Gas and Electric Company as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, RBS Securities Inc. and Wells Fargo Securities LLC as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. as co-syndication agents and lenders, (5) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-2348), Exhibit 10.2)
10.3	Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)

10.5		Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
10.6	*	Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.7	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5)
10.8	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.3)
10.9	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.2)
10.10	*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.3)
10.11	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.6)
10.12	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2012 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.4)
10.13	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.14	*	Performance Share Agreement between Anthony F. Earley, Jr. and PG&E Corporation dated September 13, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.5)
10.15	*	Restricted Stock Unit Agreement between Christopher P. Johns and PG&E Corporation dated May 9, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.4)
10.16	*	Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.18)
10.17	*	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.18)
10.18	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Jesus Soto, Jr. dated April 4, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.2)

10.19	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Edward D. Halpin dated February 3, 2012 for employment starting April 1, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-2348), Exhibit 10.21)
10.20	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Karen Austin dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.7)
10.21	*	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Nick Stavropoulos dated April 29, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-2348), Exhibit 10.8)
10.22	*	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609), Exhibit 10.10)
10.23	*	PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.24	*	PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24)
10.25	*	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
10.26	*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.27)
10.27	*	Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27)
10.28	*	Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28)
10.29	*	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.31)
10.30	*	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2)
10.31	*	Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.30)
10.32	*	Postretirement Life Insurance Plan of the Pacific Gas and Electric Company as amended and restated on February 14, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7)

10.33	*	PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)
10.34	*	Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.36)
10.35	*	Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2012) (File No. 1-12609), Exhibit 10.37)
10.36	*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40)
10.37	*	PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
10.38	*	Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3)
10.39	*	Form of Restricted Stock Unit Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.1)
10.40	*	Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.1)
10.41	*	Form of Restricted Stock Unit Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.2)
10.42	*	Form of Restricted Stock Unit Agreement for 2009 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2009 (File No. 1-12609), Exhibit 10.2)
10.43	*	Form of Restricted Stock Unit Agreement for 2013 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12609), Exhibit 10.1)
10.44	*	Form of Restricted Stock Unit Agreement for 2012 grants to directors under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2012 (File No. 1-12609), Exhibit 10.3)
10.45	*	Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 1-12609 and File No. 1-2348), Exhibit 99.1)
10.46	*	Form of Performance Share Agreement for 2013 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.4)

10.47	*	Form of Performance Share Agreement for 2012 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.2)
10.48	*	Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2011 (File No. 1-12609), Exhibit 10.2)
10.49	*	Form of Performance Share Agreement for 2010 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12609), Exhibit 10.3)
10.50	*	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3)
10.51	*	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2)
10.52	*	PG&E Corporation 2012 Officer Severance Policy, effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.6)
10.53	*	PG&E Corporation Officer Severance Policy, as amended effective as of March 1, 2012 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-12609), Exhibit 10.5)
10.54	*	PG&E Corporation Officer Severance Policy, as amended effective as of February 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.51)
10.55	*	PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49)
10.56	*	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58)
10.57	*	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
10.58	*	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.39)
10.59	*	PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54)
10.60	*	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40)
10.61	*	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)
12.1		Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company

12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
13	The following portions of the 2013 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Glossary," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Income," "Consolidated Statements of Comprehensive Income," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," and "Report of Independent Registered Public Accounting Firm."
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contract or compensatory agreement.

** Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

EXHIBIT 12.1
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings:					
Net income	\$ 866	\$ 811	\$ 845	\$ 1,121	\$ 1,250
Income tax provision	326	298	480	574	482
Fixed charges	971	891	880	799	817
Total earnings	\$ 2,163	\$ 2,000	\$ 2,205	\$ 2,494	\$ 2,549
Fixed charges:					
Interest on short-term borrowings and long-term debt, net	\$ 917	\$ 834	\$ 824	\$ 731	\$ 754
Interest on capital leases	7	9	16	18	19
AFUDC debt	47	48	40	50	44
Total fixed charges	\$ 971	\$ 891	\$ 880	\$ 799	\$ 817
Ratios of earnings to fixed charges	2.23	2.24	2.51	3.12	3.12

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

EXHIBIT 12.2
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings:					
Net income	\$ 866	\$ 811	\$ 845	\$ 1,121	\$ 1,250
Income tax provision	326	298	480	574	482
Fixed charges	971	891	880	799	817
Total earnings	\$ 2,163	\$ 2,000	\$ 2,205	\$ 2,494	\$ 2,549
Fixed charges:					
Interest on short-term borrowings and long-term debt, net	\$ 917	\$ 834	\$ 824	\$ 731	\$ 754
Interest on capital leases	7	9	16	18	19
AFUDC debt	47	48	40	50	44
Total fixed charges	\$ 971	\$ 891	\$ 880	\$ 799	\$ 817
Preferred stock dividends:					
Tax deductible dividends	\$ 9	\$ 9	\$ 9	\$ 9	\$ 9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	7	7	8	7	7
Total preferred stock dividends	16	16	17	16	16
Total combined fixed charges and preferred stock dividends	\$ 987	\$ 907	\$ 897	\$ 815	\$ 833
Ratios of earnings to combined fixed charges and preferred stock dividends	2.19	2.21	2.46	3.06	3.06

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.

EXHIBIT 12.3
PG&E CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings:					
Net income	\$ 828	\$ 830	\$ 858	\$ 1,113	\$ 1,234
Income tax provision	268	237	440	547	460
Fixed charges	1,012	931	919	850	877
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	(16)	(15)	(17)	(16)	(16)
Total earnings	\$ 2,092	\$ 1,983	\$ 2,200	\$ 2,494	\$ 2,555
Fixed charges:					
Interest on short-term borrowings and long-term debt, net	\$ 942	\$ 859	\$ 846	\$ 766	\$ 798
Interest on capital leases	7	9	16	18	19
AFUDC debt	47	48	40	50	44
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	16	15	17	16	16
Total fixed charges	\$ 1,012	\$ 931	\$ 919	\$ 850	\$ 877
Ratios of earnings to fixed charges	2.07	2.13	2.39	2.93	2.91

Note:

For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

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SELECTED FINANCIAL DATA

(in millions, except per share amounts)

PG&E Corporation

For the Year

	2013	2012	2011	2010	2009
Operating revenues	\$ 15,598	\$ 15,040	\$ 14,956	\$ 13,841	\$ 13,399
Operating income	1,762	1,693	1,942	2,308	2,299
Income from continuing operations	828	830	858	1,113	1,234
Earnings per common share from continuing operations, basic	1.83	1.92	2.10	2.86	3.25
Earnings per common share from continuing operations, diluted	1.83	1.92	2.10	2.82	3.20
Dividends declared per common share ⁽¹⁾	1.82	1.82	1.82	1.82	1.68

At Year-End

Common stock price per share	\$ 40.28	\$ 40.18	\$ 41.22	\$ 47.84	\$ 44.65
Total assets	55,605	52,449	49,750	46,025	42,945
Long-term debt (excluding current portion)	12,717	12,517	11,766	10,906	10,381
Capital lease obligations (excluding current portion) ⁽²⁾	90	113	212	248	282
Energy recovery bonds (excluding current portion) ⁽³⁾	-	-	-	423	827

Pacific Gas and Electric Company

For the Year

Operating revenues	\$ 15,593	\$ 15,035	\$ 14,951	\$ 13,840	\$ 13,399
Operating income	1,790	1,695	1,944	2,314	2,302
Income available for common stock	852	797	831	1,107	1,236

At Year-End

Total assets	55,049	51,923	49,242	45,679	42,709
Long-term debt (excluding current portion)	12,717	12,167	11,417	10,557	10,033
Capital lease obligations (excluding current portion) ⁽²⁾	90	113	212	248	282
Energy recovery bonds (excluding current portion) ⁽³⁾	-	-	-	423	827

⁽¹⁾ Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in "Liquidity and Financial Resources – Dividends" within "Management's Discussion and Analysis of Financial Condition and Results of Operations," and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of Shareholders' Equity, and Note 5 of the Notes to the Consolidated Financial Statements.

⁽²⁾ The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation's and the Utility's Consolidated Balance Sheets.

⁽³⁾ The energy recovery bonds matured in December 2012.

GLOSSARY

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

2013 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, 2013, including the information incorporated by reference into the report
AFUDC	Allowance for Funds Used During Construction
ALJ	administrative law judge
ARO	Asset retirement obligation
ASU	accounting standards update
CAISO	California Independent System Operator
CARB	California Air Resources Board
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
EPA	Environmental Protection Agency
EPS	earnings per common share
FERC	Federal Energy Regulatory Commission
GAAP	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
MGP	manufactured gas plant
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
ORA	Officer of Ratepayer Advocates
OSC	CPUC Order to Show Cause
PSEP	pipeline safety enhancement plan
QF(s)	Qualified facilities
Regional Board	California Regional Water Quality Control Board, Lahontan Region
REITS	Global real estate investment trust
RSU(s)	restricted stock unit
ROE	return on equity
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)

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount of revenue that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs (depreciation, tax, and financing expenses) of providing utility services. The primary CPUC proceedings are the GRC and the GT&S rate case which generally occur every few years and result in revenue requirements that are set for multi-year periods. The CPUC also periodically conducts a cost of capital proceeding, where it determines the capital structure the Utility must maintain (i.e., the relative weightings of common equity, long-term debt, and preferred equity) and authorizes the Utility to earn a specific rate of return on each capital component, including equity. The authorized revenue requirements the CPUC sets in the GRC and GT&S rate cases are set at levels to 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. The primary FERC proceeding is the electric TO rate case which generally occurs on an annual basis. The rate of return for the Utility's FERC jurisdictional assets is embedded in revenues authorized in the TO rate cases.

The Utility's ability to recover its GRC revenue requirements does not depend on the volume of the Utility's sales of electricity and natural gas services. This decoupling of revenues and sales eliminates volatility in the revenues earned by the Utility due to fluctuations in customer demand. The Utility's ability to recover a portion of its GT&S revenue requirements depends on the volume of natural gas transported as well as the use of its storage facilities. The Utility's ability to recover its electric transmission-related revenue requirements depends on the volume of electricity sales.

The Utility's revenue requirements are set based on forecast costs. Differences in the amount or timing between forecast costs and actual costs can occur for numerous reasons, including unanticipated costs related to storms, outages, catastrophic events, or to comply with new legislation, regulations, or orders; or third-party claims that are not recoverable through insurance. Generally, differences between actual costs and forecast costs could affect the Utility's ability to earn its authorized return (referred to as "activities impacting earnings" below). However, for certain core 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 "cost recovery activities" below). The Utility also collects additional revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose programs, such as demand response and customer energy efficiency. Therefore, although the timing and amount of these costs can impact the Utility's revenue, these costs generally do not impact net income (included in "cost recovery activities" below).

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 revenue and net income, as described more fully below.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

Summary of Changes in Net Income and Earnings per Share

PG&E Corporation's net income available for common shareholders for 2013 was \$814 million, or \$1.83 per share, as compared to \$816 million, or \$1.92 per share, for 2012. Operating results have continued to be materially affected by costs the Utility has incurred to improve the safety and reliability of its natural gas operations that are not recoverable through rates. These unrecovered costs have increased the Utility's equity needs which PG&E Corporation has funded through equity issuances that have materially diluted PG&E Corporation's EPS.

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, 2013 compared to the prior year. (See "Results of Operations" and "Natural Gas Matters" below for additional information.)

(in millions, except per share amounts)	Earnings	EPS (Diluted)
Income Available for Common Shareholders - 2012	\$ 816	\$ 1.92
Natural gas matters ⁽¹⁾	96	0.27
Growth in rate base earnings ⁽²⁾	87	0.19
Environmental-related costs ⁽³⁾	59	0.14
Reduction in authorized cost of capital ⁽⁴⁾	(166)	(0.37)
Impact of capital spending over authorized ⁽⁵⁾	(24)	(0.06)
Uneconomic project and lease termination ⁽⁶⁾	(11)	(0.03)
Gas transmission revenues	(9)	(0.02)
Increase in shares outstanding ⁽⁷⁾	-	(0.15)
Other	(34)	(0.06)
Income Available for Common Shareholders - 2013	\$ 814	\$ 1.83

⁽¹⁾ The Utility incurred net costs and capital charges related to natural gas matters of \$645 million and \$812 million, pre-tax, during 2013 and 2012, respectively. These amounts are not recoverable through rates. See "Operating and Maintenance" below.

⁽²⁾ Represents the impact of the increase in rate base as authorized in various rate cases during 2013 as compared to 2012.

⁽³⁾ Environmental-related costs were lower in 2013 compared to 2012 when the Utility incurred a significant charge for environmental remediation associated with the Hinkley natural gas compressor site.

⁽⁴⁾ Reflects the lower cost of capital authorized in the 2013 Cost of Capital proceeding. The CPUC authorized the Utility to earn a ROE of 10.40% (compared to 11.35% previously authorized) and adjusted its cost of debt beginning on January 1, 2013.

⁽⁵⁾ Represents the incremental interest and depreciation expense associated with capital expenditures that exceed the current authorized levels.

⁽⁶⁾ Represents the expenses incurred in 2013 for terminated projects and leases, compared to 2012.

⁽⁷⁾ Represents the impact of a higher number of weighted average shares outstanding during 2013, compared to 2012. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including expenses related to natural gas matters. This has no dollar impact on earnings.

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 several factors, including the timing and outcome of CPUC ratemaking proceedings, the ultimate amount of costs the Utility will continue to incur to improve the safety and reliability of its natural gas operations, the outcome of the pending investigations that commenced following the San Bruno accident including the ultimate amount of fines the Utility will be required to pay, and the timing and amount of the Utility's financing needs.

- *The Timing and Outcome of Ratemaking Proceedings* . The majority of the Utility's revenue requirements for the next several years will be determined by the outcomes of the 2014 GRC and the 2015 GT&S rate case. In the 2014 GRC, the Utility is seeking an increase in its 2014 revenue requirements of \$1.16 billion over the comparable revenues for 2013 that were previously authorized, as well as attrition increases for 2015 and 2016. The CPUC's ORA has recommended that the CPUC approve a 2014 revenue requirement that is lower than the amount authorized for 2013. A proposed decision is anticipated in the first quarter of 2014. (See "2014 General Rate Case" below.) In the 2015 GT&S rate case, the Utility is seeking an increase in its 2015 revenue requirements of \$555 million over the comparable revenues for 2014 that were previously authorized, as well as attrition increases for 2016 and 2017. The Utility has requested that the CPUC issue a final decision by the end of 2014. (See "2015 Gas Transmission and Storage Rate Case" below.) The outcome of these ratemaking proceedings can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.
- *The Ability of the Utility to Control Operating Costs and Capital Expenditures*. Net income is negatively affected when the authorized revenues are not sufficient for the Utility to recover the costs it actually incurs to provide utility services. The Utility forecasts that it will incur total pipeline-related expenses ranging from \$350 million to \$450 million in 2014 that will not be recoverable through rates. These amounts include costs to perform work under the Utility's PSEP that were disallowed by the CPUC, as well as costs related to the Utility's multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way and other gas-related work, and legal and other expenses. The Utility could record additional charges for PSEP capital to the extent the Utility's costs are higher than expected or if additional costs are disallowed by the CPUC. (See "Disallowed Capital Costs" below.) The Utility's ability to recover pipeline-related expenses beginning in 2015 also will be affected by the outcome of the 2015 GT&S rate case. Differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may affect the Utility's ability to earn its authorized ROE.
- *The Outcome of Pending Investigations and Enforcement Matters*. Three CPUC investigations are still pending against the Utility related to its natural gas operations and the San Bruno accident. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of \$2.25 billion on the Utility, consisting of a \$300 million fine payable to the State General Fund and \$1.95 billion of non-recoverable costs. If the SED's penalty recommendation is adopted, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about \$4.5 billion. (See "Pending CPUC Investigations" below.) In addition, the CPUC and the SED may impose fines or take enforcement action with respect to the Utility's self-reports of noncompliance with certain natural gas safety regulations. (See "CPUC Enforcement Matters" below.) The Utility may be required to pay additional civil or criminal penalties or incur other costs, depending on the outcome of the pending federal criminal investigation of the San Bruno accident. (See "Criminal Investigation" below.)
- *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. Future financing needs will be affected by various factors, including the timing and amount of capital expenditures and operating expenses, the amount of costs related to natural gas matters that are not recoverable through rates, and other factors described in "Liquidity and Financial Resources" below. PG&E Corporation forecasts that it will issue a material amount of equity in 2014, primarily to support the Utility's 2014 capital expenditures (which are forecasted to range from \$5 billion to \$6 billion) and to fund unrecovered costs. Depending on the outcome of the pending investigations, PG&E Corporation may be required to issue additional common stock to fund its equity contributions as the Utility pays fines and incurs additional unrecoverable gas safety-related costs. 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 changes in their respective credit ratings, the outcome of natural gas matters, 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 the section entitled "Risk Factors" below. In addition, this 2013 Annual 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. 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

PG&E Corporation

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The table below provides a summary of consolidated net income (loss) for 2013, 2012 and 2011:

(in millions)	2013	2012	2011
Consolidated Total	\$ 814	\$ 816	\$ 844
PG&E Corporation	(38)	19	13
Utility	852	797	831

PG&E Corporation's net income consists primarily of operating and maintenance expense, interest expense on long-term debt, other income from investments, and income taxes. In 2013, PG&E Corporation's operating results were primarily impacted by an impairment loss resulting from investments unrelated to PG&E Corporation's core operations with no similar activity in 2012 and by an increase in charitable contributions. There were no material changes to PG&E Corporation's operating results in 2012 compared to 2011.

Utility

The table below details certain items from the Utility's accompanying Consolidated Statements of Income for 2013, 2012, and 2011. The presentation below separately identifies activities that impact earnings and cost recovery activities that do not impact earnings.

Activities that impact earnings (net income) primarily include revenues authorized by the CPUC and FERC in the various rate cases that are designed to recover the Utility's costs to own and operate its assets and provide it with an opportunity to earn its authorized rate of return on its rate base. Expenses that impact earnings include costs in excess of amounts authorized and costs for which the Utility does not seek recovery. (See "Utility Activities Impacting Earnings" below.) Activities that do not impact earnings include revenues collected to recover certain costs that the Utility is authorized to pass on to customers, including costs to purchase electricity and natural gas, as well as costs to fund public purpose programs. They also include revenues authorized in various rate cases that are designated for a specific purpose such as the payment of pension costs. (See "Utility Cost Recovery Activities" below.)

(in millions)	2013			2012			2011		
	Earning Activities	Cost Recovery Activities	Total Utility	Earning Activities	Cost Recovery Activities	Total Utility	Earning Activities	Cost Recovery Activities	Total Utility
Electric operating revenues	\$ 6,465	\$ 6,024	\$ 12,489	\$ 6,414	\$ 5,600	\$ 12,014	\$ 6,150	\$ 5,451	\$ 11,601
Natural gas operating revenues	1,776	1,328	3,104	1,772	1,249	3,021	1,696	1,654	3,350
Total operating revenues	8,241	7,352	15,593	8,186	6,849	15,035	7,846	7,105	14,951
Cost of electricity	-	5,016	5,016	-	4,162	4,162	-	4,016	4,016
Cost of natural gas	-	968	968	-	861	861	-	1,317	1,317
Operating and maintenance	4,374	1,368	5,742	4,563	1,482	6,045	4,087	1,372	5,459
Depreciation, amortization, and decommissioning	2,077	-	2,077	1,928	344	2,272	1,815	400	2,215
Total operating expenses	6,451	7,352	13,803	6,491	6,849	13,340	5,902	7,105	13,007
Operating income	1,790	-	1,790	1,695	-	1,695	1,944	-	1,944
Interest income ⁽¹⁾			8			6			5
Interest expense ⁽¹⁾			(690)			(680)			(677)
Other income, net ⁽¹⁾			84			88			53
Income before income taxes			1,192			1,109			1,325
Income tax provision ⁽¹⁾			326			298			480
Net income			866			811			845

Preferred stock dividend requirement	<u>14</u>	<u>14</u>	<u>14</u>
Income Available for Common Stock	<u>\$ 852</u>	<u>\$ 797</u>	<u>\$ 831</u>

(1) Items represent activities that impact earnings for 2013, 2012, and 2011.

Utility Activities Impacting Earnings

The following discussion presents the Utility's operating results for activities impacting earnings for 2013, 2012, and 2011.

Operating Revenues

The Utility's electric and natural gas operating revenues increased by \$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 return authorized in the 2013 Cost of Capital proceeding.

The Utility's electric and natural gas operating revenues increased by \$340 million, or 4%, in 2012 compared to 2011 primarily due to an increase in revenues authorized in various rate cases and increases in natural gas storage revenues.

Operating and Maintenance

The Utility's operating and maintenance expenses decreased by \$189 million, or 4%, in 2013 compared to 2012, primarily due to decreases of \$167 million for net costs incurred in connection with natural gas matters (see table below) and \$88 million for environmental remediation costs associated with a significant charge in 2012 for the Hinkley natural gas compressor station site. These costs were partially offset by increases in other expenses that were not material. In each of 2013 and 2012, the Utility incurred expenses that were approximately \$250 million higher than the level of authorized revenue requirements to improve the safety and reliability of its operations that will not be recovered in rates.

The Utility's operating and maintenance expenses increased by \$476 million, or 12%, in 2012 compared to 2011, primarily due to costs incurred to improve the safety and reliability of electric and natural gas operations that were approximately \$250 million higher than amounts assumed under the 2011 rate cases. The remaining increase was primarily attributable to an increase of \$73 million for net costs incurred in connection with natural gas matters (see table below), and a \$56 million charge related to employee operational performance incentives.

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

(in millions)	2013	2012	2011
Pipeline-related expenses ⁽¹⁾⁽²⁾	\$ 387	\$ 477	\$ 483
Disallowed capital	196	353	-
Accrued fines	22	17	200
Third-party liability claims	110	80	155
Insurance recoveries	(70)	(185)	(99)
Contribution to City of San Bruno	-	70	-
Total natural gas matters	\$ 645	\$ 812	\$ 739

(1) Includes \$137 million, \$268 million, and \$331 million for work performed under the Utility's PSEP in 2013, 2012, and 2011, respectively.

(2) The decrease for 2013 reflects amounts that were authorized for recovery in the CPUC's PSEP December 2012 decision as well as lower legal and other expenses in 2013.

Pipeline-related expenses include costs to validate safe operating pressures, conduct strength testing, and perform other work associated with the Utility's PSEP; costs related to the Utility's multi-year effort to identify and remove encroachments (e.g. building structures and vegetation overgrowth) from transmission pipeline rights-of-way, and costs to improve the integrity of transmission pipelines and to perform other gas-related work; and legal and other expenses. In 2013, the Utility completed its "centerline" mapping survey of its entire gas transmission system to locate, mark, and map the center of all transmission pipelines. The Utility recorded charges of \$196 million and \$353 million in 2013 and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. The additional charge in 2013 primarily reflects a change in project portfolio involving higher unit costs to replace pipelines than originally forecast. (See "Natural Gas Matters – Disallowed Capital Costs" below.)

The Utility recorded charges of \$22 million and \$17 million in 2013 and 2012, respectively, for fines imposed on the Utility by the CPUC and SED in connection with various self-reported violations and other enforcement matters. The Utility accrued \$200 million in 2011 as the minimum amount of fines deemed probable that the Utility will pay to the State General Fund in connection with the three pending CPUC investigations. (See "Natural Gas Matters – Pending CPUC Investigations" below.)

The Utility has settled the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury, property damage, and other relief, following the San Bruno accident. The Utility has recorded cumulative charges of \$565 million for third-party claims related to the San Bruno accident, reflecting its best estimate of probable loss. These costs were partially offset by cumulative insurance recoveries of \$354 million. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses of \$86 million) will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by \$149 million, or 8%, in 2013 compared to 2012, and by \$113 million, or 6%, in 2012 compared to 2011, primarily due to the impact of capital additions.

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 income tax provision increased by \$28 million, or 9%, in 2013 compared to 2012. The effective tax rates were 27% in both 2013 and 2012.

The Utility's income tax provision decreased by \$182 million, or 38%, in 2012 compared to 2011. The effective tax rates were 27% and 36% for 2012 and 2011, respectively. The effective tax rate decreased primarily due to lower state and federal taxes for non-tax deductible penalties related to natural gas matters.

The differences between the Utility's income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations for 2013, 2012, and 2011 were as follows:

	2013	2012	2011
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)	(2.2)	(3.0)	1.6
Effect of regulatory treatment of fixed asset differences	(3.8)	(3.9)	(4.2)
Tax credits	(0.4)	(0.6)	(0.5)
Benefit of loss carryback	(1.0)	(0.4)	(2.1)
Non deductible penalties	0.7	0.5	6.3
Other, net	(0.9)	(0.8)	0.1
Effective tax rate	27.4%	26.8%	36.2%

Utility Cost Recovery Activities

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.) The volume of power purchased by the Utility is driven by customer demand, the availability of the Utility's own generation facilities, 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 legislative and regulatory requirements, and by costs associated with complying with California's GHG laws.

(in millions)	2013	2012	2011
Cost of purchased power	\$ 4,696	\$ 3,873	\$ 3,719
Fuel used in own generation facilities	320	289	297
Total cost of electricity	\$ 5,016	\$ 4,162	\$ 4,016
Average cost of purchased power per kWh	\$ 0.094	\$ 0.079	\$ 0.089
Total purchased power (in millions of kWh)	49,941	48,933	41,958

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.) The Utility's future cost of natural gas will be affected 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)	2013	2012	2011
Cost of natural gas sold	\$ 807	\$ 676	\$ 1,136
Transportation cost of natural gas sold	161	185	181
Total cost of natural gas	\$ 968	\$ 861	\$ 1,317
Average cost per Mcf of natural gas sold	\$ 3.54	\$ 2.91	\$ 4.49
Total natural gas sold (in millions of Mcf) ⁽¹⁾	228	232	253

⁽¹⁾ One thousand cubic feet

Operating Expenses

The Utility's operating expenses also include certain recoverable costs that the Utility is required to incur as part of its operations and include public purpose programs, pension, and other continuous business expenses. Additionally, operating expenses in 2012 and 2011 include the amortization of energy recovery bonds regulatory asset which fully amortized in 2012. If the Utility were to spend over authorized amounts, these expenses could have an impact to earnings.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations 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 levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load, volatility in energy commodity costs, collateral requirements related to price risk management activities, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and long-term financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of \$4.0 billion, including \$500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, and pay dividends primarily depends on PG&E Corporation's access to the capital and credit markets and the level of cash distributions received from the Utility. PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation's stock issuances used to fund Utility equity needs attributable to unrecoverable costs and penalties have had and will continue to have a dilutive effective on PG&E Corporation's EPS. PG&E Corporation also may use draws under its revolving credit facility or issuances under its commercial paper program to occasionally fund equity contributions on an interim basis.

PG&E Corporation and the Utility have \$889 million of long-term debt maturing within the next 6 months. PG&E Corporation and the Utility plan to repay this debt with capital market financings.

Further, given the Utility's significant ongoing capital expenditures, the Utility will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure. 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, incremental work to improve safety and reliability of electric and gas operations in excess of authorized revenue requirements, and environmental remediation costs. The Utility's equity needs would also increase to the extent it is required to pay fines or penalties in connection with pending investigations. (See "Natural Gas Matters" below.)

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of the pending investigations related to natural gas matters and the San Bruno accident. PG&E Corporation's and the Utility's credit ratings may affect their access to the credit and capital markets and their respective financing costs in those markets. Credit rating downgrades may increase the cost of short-term borrowing, including PG&E Corporation's and the Utility's commercial paper, as well as the costs associated with their respective credit facilities, and long-term debt.

PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. The following table summarizes PG&E Corporation's and the Utility's cash positions:

(in millions)	December 31,	
	2013	2012
PG&E Corporation	\$ 231	\$ 207
Utility	65	194
Total consolidated cash and cash equivalents	\$ 296	\$ 401

In addition to these cash and cash equivalents, PG&E Corporation and the Utility hold 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.)

Revolving Credit Facilities and Commercial Paper Programs

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as the original 2011 credit agreements.

In January 2014, PG&E Corporation established a new commercial paper program, the borrowings of which will be used primarily to cover fluctuations in cash flow requirements. PG&E Corporation will treat the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2013:

	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
(in millions)						
PG&E Corporation	April 2018	\$ 300 ⁽¹⁾	\$ -	\$ 260	\$ -	\$ 40
Utility	April 2018	3,000 ⁽²⁾	79	-	914 ⁽³⁾	2,007 ⁽³⁾
Total revolving credit facilities		\$ 3,300	\$ 79	\$ 260	\$ 914	\$ 2,047

⁽¹⁾ Includes a \$100 million sublimit for letters of credit and a \$100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

⁽²⁾ Includes a \$1.0 billion sublimit for letters of credit and a \$300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

⁽³⁾ The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2013, the average outstanding borrowings under PG&E Corporation's revolving credit facility were \$214 million and the maximum outstanding balance during the year was \$260 million. For 2013, the Utility's average outstanding commercial paper balance was \$542 million and the maximum outstanding balance during the year was \$1.1 billion. The Utility did not borrow under its credit facility in 2013.

The revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under 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. In addition, 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. At December 31, 2013, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

2013 Financings

Utility

The following table summarizes long-term debt issuances in 2013:

(in millions)	Issue Date	Amount
Senior Notes		
3.25%, due 2023	June 14	\$ 375
4.60%, due 2043	June 14	375
3.85%, due 2023	November 12	300
5.125%, due 2043	November 12	500
Total debt issuances in 2013		\$ 1,550

The net proceeds from the issuance of Utility senior notes in 2013 were used to fund maturing debt, to repurchase and extinguish \$461 million principal amount, net of \$15 million of premiums and \$6 million of accrued interest, of the Utility's outstanding 4.80% Senior Notes due March 1, 2014, fund capital expenditures, and for general corporate purposes.

The Utility also received cash contributions of \$1.1 billion from PG&E Corporation during 2013 to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC.

PG&E Corporation

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to \$400 million. As of December 31, 2013, PG&E Corporation had sold common stock having an aggregate gross sales price of \$395 million and had the ability to issue an additional \$5 million of its common stock under this agreement. During 2013, PG&E Corporation paid commissions of \$3 million under this agreement. PG&E Corporation terminated this agreement in January 2014 and intends to enter into a new equity distribution agreement providing for the sale of PG&E Corporation's common stock having an aggregate gross sales price of \$500 million.

During 2013, PG&E Corporation issued 26 million shares of its common stock for aggregate net cash proceeds of \$1,045 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of \$300 million, net of fees and commissions;
- 8 million shares that were issued for cash proceeds of \$290 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 11 million shares were sold for cash proceeds of \$455 million, net of commissions paid of \$4 million, under equity distribution agreements.

The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. For the year ended December 31, 2013, PG&E Corporation made equity contributions to the Utility of \$1.1 billion. PG&E Corporation forecasts that it will need to continue to issue additional common stock to fund the Utility's equity needs.

Dividends

The Board of Directors of PG&E Corporation and the Utility have each adopted a common stock dividend policy that is designed to meet the following three objectives:

- *Comparability* : Pay a dividend competitive with the securities of comparable companies based on payout ratio (the proportion of earnings paid out as dividends) and, with respect to PG&E Corporation, yield (i.e., dividend per share divided by share price);
- *Flexibility*: Allow sufficient cash to pay a dividend and to fund investments while avoiding having to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- *Sustainability*: Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

Each Board of Directors retains authority to change the common stock dividend rate at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors. In addition, before declaring a dividend, the CPUC requires 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. The Boards of Directors must also consider the CPUC requirement that the Utility maintain, on average, its CPUC-authorized capital structure including a 52% equity component.

The Board of Directors of PG&E Corporation declared dividends of \$0.455 per share for each of the quarters of 2013, 2012, and 2011, for annual dividends of \$1.82 per share.

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

(in millions)	2013	2012	2011
PG&E Corporation:			
Common stock dividends paid	\$ 782	\$ 746	\$ 704
Common stock dividends reinvested in Dividend Reinvestment and Stock Purchase Plan	22	22	24
Utility:			
Common stock dividends paid	\$ 716	\$ 716	\$ 716
Preferred stock dividends paid	14	14	14

In December 2013, the Board of Directors of PG&E Corporation declared quarterly dividends of \$0.455 per share, totaling \$208 million, of which \$202 million was paid in January 2014 to shareholders of record on December 31, 2013.

In December 2013, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable in February 2014, to shareholders of record on January 31, 2014.

As the Utility focuses on improving the safety and reliability of its natural gas and electric operations, and subject to the outcome of the matters described under "Natural Gas Matters" below, PG&E Corporation expects that its Board will continue to maintain the current quarterly common stock dividend.

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 2013, 2012, and 2011 were as follows:

(in millions)	2013	2012	2011
Net income	\$ 866	\$ 811	\$ 845
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,077	2,272	2,215
Allowance for equity funds used during construction	(101)	(107)	(87)
Deferred income taxes and tax credits, net	1,103	684	582
PSEP disallowed capital expenditures	196	353	-
Other	299	236	289
Effect of changes in operating assets and liabilities:			
Accounts receivable	(152)	(40)	(227)
Inventories	(10)	(24)	(63)
Accounts payable	99	(26)	51
Income taxes receivable/payable	(377)	(50)	(192)
Other current assets and liabilities	(404)	272	36
Regulatory assets, liabilities, and balancing accounts, net	(202)	291	(100)
Other noncurrent assets and liabilities	22	256	414
Net cash provided by operating activities	\$ 3,416	\$ 4,928	\$ 3,763

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 settlement payments the Utility received from the U.S Treasury related to 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.

During 2012, net cash provided by operating activities increased by \$1.2 billion compared to 2011 when the Utility's net collateral payments were \$352 million higher. Also, in 2012, the Utility received settlement payments of \$250 million, net of legal fees, from the U.S. Treasury related to the Utility's spent nuclear fuel disposal costs and made tax payments that were \$224 million lower than in 2011. 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 2014 GRC and 2015 GT&S rate cases;
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments;
- the timing and amount of insurance recoveries related to third party claims;
- the timing and amount of fines or penalties that may be imposed, as well as any costs associated with remedial actions the Utility may be required to implement;
- the timing and amount of costs the Utility incurs, but does not recover, to improve the safety and reliability of its natural gas system (see “Operating and Maintenance” above and “Natural Gas Matters” below); and
- the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay (see Note 12 of the Notes to the Consolidated Financial Statements).

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 occurrence of storms and other events causing outages or damages to the Utility’s infrastructure. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the 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 2013, 2012, and 2011 were as follows:

(in millions)	2013	2012	2011
Capital expenditures	\$ (5,207)	\$ (4,624)	\$ (4,038)
Decrease in restricted cash	29	50	200
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,619	1,133	1,928
Purchases of nuclear decommissioning trust investments	(1,604)	(1,189)	(1,963)
Other	21	16	14
Net cash used in investing activities	\$ (5,142)	\$ (4,614)	\$ (3,859)

Net cash used in investing activities increased by \$528 million in 2013 compared to 2012. This increase was 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.

Net cash used in investing activities increased by \$755 million in 2012 compared to 2011. This increase was primarily due to an increase of \$586 million in capital expenditures and a reduction in restricted cash released for resolved Chapter 11 disputed claims of \$150 million.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility forecasts that it will incur between \$5 billion and \$6 billion in capital expenditures for 2014. Most of the Utility’s revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO, and GT&S rate cases. The Utility’s ability to invest in its electric and natural gas systems and develop new generation facilities is subject to many risks, including risks related to securing adequate and reasonably priced financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards.

Financing Activities

The Utility's cash flows from financing activities for 2013, 2012, and 2011 were as follows:

(in millions)	2013	2012	2011
Borrowings under revolving credit facilities	\$ -	\$ -	\$ 208
Repayments under revolving credit facilities	-	-	(208)
Net issuances (repayments) of commercial paper, net of discount of \$2 in 2013, \$3 in 2012, and \$4 in 2011	542	(1,021)	782
Proceeds from issuance of short-term debt	-	-	250
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$18 in 2013, \$13 in 2012, and \$8 in 2011	1,532	1,137	792
Short-term debt matured	-	(250)	(250)
Long-term debt matured or repurchased	(861)	(50)	(700)
Energy recovery bonds matured	-	(423)	(404)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution	1,140	885	555
Other	(26)	28	54
Net cash provided by (used in) financing activities	\$ 1,597	\$ (424)	\$ 349

In 2013, net cash provided by financing activities increased by \$2.0 billion compared to the same period in 2012. In 2012, net cash provided by financing activities decreased by \$773 million compared to 2011. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

PG&E Corporation

PG&E Corporation affiliates hold four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of \$362 million and received \$275 million in benefits and customer payments from 2010 to 2013. PG&E Corporation has no material remaining commitment to fund these agreements. Lease payments, investment contributions, benefits, and customer payments received are included in cash flows from operating and investing activities within the Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the years ended December 31, 2013, 2012, and 2011: dividend payments, common stock issuances, borrowings and repayments under its revolving credit facility, and transactions between PG&E Corporation and the Utility.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2013:

(in millions)	Payment due by period				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Contractual Commitments:					
Utility					
Long-term debt ⁽¹⁾ :					
Fixed rate obligations	\$ 1,181	\$ 1,258	\$ 2,718	\$ 18,708	\$ 23,865
Variable rate obligations	2	326	651	211	1,190
Purchase obligations ⁽²⁾ :					
Power purchase agreements:					
Qualifying facilities	913	1,294	856	1,614	4,677
Renewable energy (other than QF)	1,906	4,211	4,066	30,242	40,425
Other power purchase agreements	829	1,492	1,324	2,984	6,629
Natural gas supply, transportation, and storage	727	348	216	756	2,047
Nuclear fuel agreements	145	308	280	647	1,380
Pension and other benefits ⁽³⁾	398	796	796	398	2,388
Capital lease obligations ⁽²⁾	27	46	30	8	111
Operating leases ⁽²⁾	42	71	51	193	357
Preferred dividends ⁽⁴⁾	14	28	28	-	70
PG&E Corporation					
Long-term debt ⁽¹⁾ :					
Fixed rate obligations	355	-	-	-	355
Total	6,539	10,178	11,016	55,761	83,494

⁽¹⁾ Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2013 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.)

⁽²⁾ See Note 14 of the Notes to the Consolidated Financial Statements.

⁽³⁾ See Note 11 of the Notes to the Consolidated Financial Statements. 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.

NA TURAL GAS MATTERS

Since the San Bruno accident, PG&E Corporation and the Utility have incurred total cumulative charges of approximately \$2.5 billion related to natural gas matters that are not recoverable through rates, as shown in the following table:

(in millions)	2013	2012	2011	2010	Total
Pipeline-related expenses ⁽¹⁾	\$ 387	\$ 477	\$ 483	\$ 63	\$ 1,410
Disallowed capital ⁽²⁾	196	353	-	-	549
Accrued fines ⁽³⁾	22	17	200	-	239
Third-party liability claims ⁽⁴⁾	110	80	155	220	565
Insurance recoveries ⁽⁴⁾	(70)	(185)	(99)	-	(354)
Contribution ⁽⁵⁾	-	70	-	-	70
Total natural gas matters	\$ 645	\$ 812	\$ 739	\$ 283	\$ 2,479

(1) Cumulative expenses through December 31, 2013 include PSEP-related expenses of \$736 million and other gas safety-related work of \$348 million.

(2) See “Disallowed Capital Costs” below.

(3) See “Pending CPUC Investigations” and “Other Enforcement Matters” below.

(4) The Utility has settled substantially all of the third-party liability claims related to the San Bruno accident. See “Operating and Maintenance” above and “Note 14 of the Consolidated Financial Statements” below.

(5) On March 12, 2012, the Utility and the City of San Bruno entered into an agreement under which the Utility contributed \$70 million to support the city and the community’s recovery efforts.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility that 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.

The SED has issued investigative reports and briefs in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations. In July 2013, the SED recommended that the CPUC impose what the SED characterizes as a penalty of \$2.25 billion on the Utility, allocated as follows: (1) \$300 million as a fine to the State General Fund, (2) \$435 million for a portion of costs related to the Utility’s PSEP that were previously disallowed by the CPUC and funded by shareholders, and (3) \$1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future costs. (See “Disallowed Capital Costs” below.) If the SED’s penalty recommendation is adopted, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about \$4.5 billion. Other parties, including the City of San Bruno, TURN, the CPUC’s ORA, and the City and County of San Francisco, have recommended total penalties of at least \$2.25 billion, including fines payable to the State General Fund of differing amounts.

The ALJs who oversee the investigations are expected to issue one or more presiding officers’ decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued. Based on the CPUC’s rules, the presiding officer’s decisions would become the final decisions of the CPUC 30 days after issuance unless the Utility or another party filed an appeal with the CPUC, or a CPUC commissioner requested that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties would have 15 days to provide comments but the CPUC could act before considering any comments.

At December 31, 2013, the Consolidated Balance Sheets included an accrual of \$200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system will be considered; whether the Utility’s costs to perform any required remedial actions will be considered; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation’s and the Utility’s financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See “Disallowed Capital Costs” below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

Other CPUC Enforcement Matters

PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with the following matters.

Gas Safety Citation Program. The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of their natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. The SED can exercise its discretion in determining whether to impose fines and the amount of such fines, or whether to take other enforcement action, based on the totality of the circumstances. The SED can consider such factors as 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. In January 2012, the SED imposed fines of \$16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from \$50,000 to \$8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

Natural Gas Transmission Pipeline Rights-of-Way. In 2012, the Utility notified the CPUC and the SED that it is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose fines on the Utility or take other enforcement action in connection with this matter.

Orders to Show Cause. In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately \$14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. The Utility recorded this amount as an expense for 2013. On January 23, 2014, the Utility filed an application for the rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. Briefing on this OSC was completed on January 31, 2014.

Disallowed Capital Costs

In 2011, the CPUC ordered all natural gas operators in California to submit proposed plans to modernize and upgrade their natural gas transmission systems as well as associated cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP application that was filed in August 2011, but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. In October 2013, the Utility updated its PSEP application to present the results of its completed search and review of records relating to validation of operating pressure for all of the approximately 6,750 miles of the Utility's natural gas transmission pipelines. The Utility requested that the CPUC approve changes to the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects, and that the CPUC adjust authorized revenue requirements to reflect these changes. The Utility has requested that the CPUC issue a final decision by August 2014.

As of December 31, 2013, the Utility has recorded cumulative charges of \$549 million for PSEP capital costs that are expected to exceed the amount to be recovered. The Utility has requested that the CPUC authorize capital costs of \$766 million under the PSEP, reflecting the proposed changes in the PSEP update application. Of this amount, approximately \$280 million is recorded in Property, Plant, and Equipment on the Consolidated Balance Sheets at December 31, 2013. The Utility could record additional charges to the extent PSEP capital costs are higher than currently expected, or if additional capital costs are disallowed by the CPUC. The Utility's ability to recover PSEP capital costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

Criminal Investigation

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. A criminal charge or finding would further harm the Utility's reputation. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

Third-party Liability Claims

See Note 14 of the Notes to the Consolidated Financial Statements.

Class Action Complaint

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than \$100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

Other Pending Lawsuits and Claims

At December 31, 2013, there were also four 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 have filed a consolidated complaint with the San Mateo County Superior Court. The court has lifted the stay on these proceedings for the limited purpose of allowing the parties to exchange information and discuss possible resolution. A case management conference is scheduled for April 18, 2014. The remaining purported shareholder derivative lawsuit, filed in the U.S. District Court for the Northern District of California, remains stayed.

In February 2011, the Board of Directors of PG&E Corporation authorized PG&E Corporation to reject a demand made by another shareholder that the Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including Board of Directors members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board of Directors deems such investigation or litigation appropriate.

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

REGULATORY MATTERS

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

2014 General Rate Case

On November 15, 2012, the Utility filed its 2014 GRC application with the CPUC. In the Utility's GRC, the CPUC will determine the revenue requirements that the Utility is authorized to collect through rates from 2014 through 2016 to recover anticipated costs associated with electric generation operations and electric and natural gas distribution operations. The Utility has requested that the CPUC authorize a total revenue requirement of \$7.8 billion for 2014, representing an increase of approximately \$1.16 billion over the comparable authorized revenues for 2013. The Utility also has requested that the CPUC authorize attrition increases in 2015 and 2016 of \$436 million and \$486 million, respectively. The requested increase is intended to allow the Utility to recover the costs it forecasts it will incur to continue making improvements to the safety and reliability of its operations.

The CPUC's ORA recommended that the Utility's 2014 revenue requirements be reduced by \$125 million from amounts authorized in 2013, approximately \$1.29 billion lower than the Utility's current forecast. The ORA also has recommended attrition increases of \$169 million for 2015 and \$160 million for 2016. The ORA's recommendations reflected reductions across all operations represented in the GRC. Twelve other parties, including TURN, also submitted recommendations in the 2014 GRC.

A proposed decision is anticipated in the first quarter of 2014. Although it is uncertain when the CPUC will issue a final decision, any approved revenue requirement changes will be effective as of January 1, 2014.

2015 Gas Transmission and Storage Rate Case

On December 19, 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. This is an increase of \$555 million over the Utility's authorized revenue requirements of \$731 million for 2014, which includes revenue requirements approved by the CPUC for both GT&S and PSEP. The Utility's forecasts for the 2015 GT&S rate case period are consistent with state law, which requires gas corporations to develop a plan to identify and minimize hazards and systemic risk for public and employee safety. The forecasts include the continuation of work begun in the Utility's PSEP, such as testing pipelines to verify safe operating pressures, replacing older pipelines, installing more valves, and inspecting the interior of more pipelines.

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 also requested additional revenue requirement increases of \$61 million in 2016 and \$168 million in 2017 for increasing capital expenditures and the associated growth in rate base, as well as increasing costs of labor, materials, and other expenses. The Utility also has proposed eliminating the current mechanism that subjects a portion of the Utility's transportation-only revenue requirement to market risk, replacing it with two-way balancing accounts to allow the Utility to record differences between billed revenues and the Utility's authorized revenue requirements. Any over-collections would be returned to customers and any under-collections would be paid by customers, with no additional risk or benefit for shareholders.

The Utility has not requested rate recovery for certain costs it forecasts it will incur during 2015 through 2017. These forecast costs include costs related to the Utility's multi-year effort to identify and remove encroachments from gas transmission pipeline rights-of-way, approximately \$75 million over the three year period to pressure test pipelines placed into service after 1961, and approximately \$75 million of remedial costs associated with the Utility's pipeline corrosion control program over the three year period.

The Utility has requested that the CPUC issue a final decision by the end of 2014 so that any authorized revenue requirement adjustments can become effective on January 1, 2015. If the CPUC has not yet issued a final decision, then, in accordance with the CPUC's decision in the Utility's last GT&S rate case, there will be an automatic 2% increase in rates on January 1, 2015 that will remain in effect until the CPUC issues a final decision in the 2015 GT&S rate case. Given the significant revenue requirement increase the Utility has requested, the Utility plans to ask the CPUC for an order to make any authorized revenue requirement changes effective on January 1, 2015, in the event that the CPUC issues its final decision after that date.

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. 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 the Utility's future financial results.

Electric Transmission Owner Rate Cases

On January 17, 2014, the FERC approved the settlement of the Utility's TO rate case that was filed in September 2012. Under the settlement the Utility's annual retail revenue requirement was increased from \$934 million to \$1,017 million effective as of May 1, 2013. The Utility has collected revenues between May 1 and September 30, 2013 at the higher as-filed rates requested in the Utility's application. The Utility will refund to customers the difference between revenues collected at the higher as-filed rates and the rates set in the FERC-approved settlement agreement.

On September 24, 2013, the FERC accepted the Utility's TO rate case that the Utility filed on July 24, 2013, making the proposed rates effective October 1, 2013, subject to refund, pending a final decision by the FERC. The Utility requested a retail revenue requirement of \$1,072 million and an ROE of 10.9%. The proposed rates represent a \$55 million increase to the annual revenue requirement set in the FERC-approved settlement agreement described in the preceding paragraph. Hearings are currently being held in abeyance while settlement discussions are held.

Oakley Generation Facility

In December 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. The CPUC's denial of various applications for rehearing that had been filed with respect to its December 2012 decision was appealed to the California Court of Appeal. On February 5, 2014, the California Court of Appeal issued a ruling that annulled the CPUC's decision after the court determined that the evidence presented did not support a finding of need for the Oakley facility. The Utility is reviewing the court's decision.

Diablo Canyon Nuclear Power Plant

In 2009, the Utility filed an application with the NRC to renew the operating licenses for the two operating units at Diablo Canyon. (The current licenses expire in 2024 and 2025.) In May 2011, after an earthquake and resulting tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan, the NRC granted the Utility's request to delay processing the Utility's application while certain advanced seismic studies were completed by the Utility. The Utility is currently assessing the data from recently completed advanced seismic studies along with other available seismic data. The Utility will not make any decisions about whether to request that the NRC resume processing the license renewal application until this assessment is completed and provided to the NRC. The Utility anticipates that it will complete its assessment by June 2014. In order for the NRC to issue renewed operating licenses, the California Coastal Commission must determine that license renewal is consistent with federal and state coastal laws. The disposition of the Utility's relicensing application also will be affected by the terms and timing of the NRC's "waste confidence" decision regarding the environmental impacts of the storage of spent nuclear fuel. The NRC has stated that it will not take action in licensing or re-licensing proceedings until it issues a new "waste confidence decision." (See "Risk Factors" below.)

The CPUC is considering the Utility's December 2012 application to recover estimated costs to decommission the Utility's nuclear facilities at Diablo Canyon and the retired nuclear facility Humboldt Bay Power Plant Unit 3. The Utility files an application with the CPUC every three years requesting approval of the Utility's estimated decommissioning costs and authorization to recover those costs through rates. The CPUC bifurcated the proceeding to allow for the decommissioning cost estimate associated with Humboldt Bay to be addressed first and all other matters (including the Diablo Canyon decommissioning cost estimate and all rate-related issues) to be addressed in a second phase. On January 28, 2014, the assigned ALJ issued a proposed decision in the first phase that would authorize \$679 million to complete the decommissioning at Humboldt Bay, approximately \$48 million lower than the amount requested by the Utility. The Utility anticipates that the CPUC will issue a final decision in the first quarter of 2014. In the second phase, TURN has recommended that the CPUC adopt a decommissioning cost estimate for Diablo Canyon that is approximately \$1.1 billion lower than the Utility's estimate of approximately \$2.8 billion. The Utility anticipates the CPUC will issue a proposed decision in the second phase during the second quarter of 2014. (See the discussion of the 2012 Nuclear Decommissioning Cost Triennial Proceeding in Note 2 of the Notes to the Consolidated Financial Statements.)

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 carbon dioxide 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 "Risk Factors" below.)

Remediation

The Utility is required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include 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. 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. (See Note 14 of the Notes to the Consolidated Financial Statements.)

Hinkley Site

The Utility's remediation and abatement efforts at the Hinkley natural gas compressor site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. The Regional Board has certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue the final project permits and a final clean-up order in phases through 2014 and into 2015. As the permits and order are issued, the Utility will obtain additional clarity on the total costs associated with the final remedy and related activities. The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provided replacement water to affected residents. (See Note 14 of the Notes to the Consolidated Financial Statements for additional information.) At December 31, 2013, \$190 million was accrued in the Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Hinkley site. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The Utility expects to submit its final remedial design plan in 2014 for approval to begin construction of an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River. At December 31, 2013, \$264 million was accrued in the Consolidated Balance Sheets for estimated undiscounted future remediation costs associated with the Topock site. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

Climate Change

A report issued in 2012 by the U.S. EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. (See "Risk Factors" below.) Although no comprehensive federal legislation has been enacted to address the reduction of GHG emissions, the California legislature has taken action to address climate change.

California Assembly Bill 32 requires the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. The CARB is the state agency charged with monitoring GHG levels and adopting regulations to implement and enforce AB 32. The CARB has approved various regulations to implement AB 32, including 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 the major sources of GHG emissions. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. The cap and trade program's first two-year compliance period, which began January 1, 2013, applies to the electricity generation and large industrial sectors. The next three-year compliance period, from January 1, 2015 through December 31, 2017, will expand to include the natural gas supply and transportation sectors, effectively covering all the capped sectors until 2020. During each year of the program, the CARB will issue emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHGs emissions allowed for that year. Emitters can obtain allowances from the CARB at quarterly auctions held by the CARB or from third parties or exchanges in the market for trading GHG allowances. The CARB is allocating a fixed number of allowances (which will decrease each year) for free to regulated electric distribution utilities, including the Utility, for the benefit of their electricity customers. The utilities are required to consign their electricity-related allowances for auction by the CARB. The CPUC has ordered the utilities to allocate their electricity-related auction revenues among certain classes of their customers. Although the CPUC has previously authorized the utilities to recover their electricity-related GHG compliance costs through rates, the recovery of these costs has been temporarily deferred until May 2014. In addition, the CARB may allocate a number of allowances for free to natural gas suppliers, including the Utility, for the benefit of the Utility's natural gas customers. The Utility has filed requests at the CPUC for authority to recover the natural gas supplier-related compliance costs from natural gas customers on an annual basis effective January 1, 2015.

The Utility expects all costs and revenues associated with GHG cap-and-trade to be passed through to customers.

Clean Water Act

The EPA published draft regulations in April 2011 to implement the requirements of the federal Clean Water Act that requires 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. In June 2012, the EPA proposed changes to these draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. It is currently uncertain when the EPA will issue final regulations.

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 nuclear power plants, including Diablo Canyon. The committee's consultant is expected to submit a final report to the California Water Board in 2014. 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 compliance 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.

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 2 (PG&E Corporation's tax equity financing agreements) and Note 14 of the Notes to the Consolidated Financial Statements (the Utility's commodity purchase agreements).

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" 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 natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk.

The Utility uses value-at-risk to measure its shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. The Utility's value-at-risk calculated under the methodology described above was approximately \$14 million and \$13 million at December 31, 2013 and 2012, respectively. During the 12 months ended December 31, 2013, the Utility's approximate high, low, and average values-at-risk were \$14 million, \$9 million and \$12 million, respectively. During 2012, the value-at-risk amounts were \$13 million, \$10 million and \$12 million, respectively. (See Note 9 of the Notes to the Consolidated Financial Statements 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, 2013 and December 31, 2012, if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments, the impact on net income over the next 12 months would be \$11 million and \$7 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, 2013 and December 31, 2012:

(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, 2013	\$ 87	\$ (9)	\$ 78	2	34
December 31, 2012	94	(9)	85	2	62

⁽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.

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 2011 through 2013.

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. At December 31, 2013, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of \$6.5 billion and regulatory liabilities (including current balancing accounts payable) of \$6.8 billion.

In addition, regulatory accounting standards require recognition of a loss if it becomes probable that capital expenditures under construction (or recently completed 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 the lower end of the range of possible losses to the extent there is a high degree of uncertainty in the Utility's forecast of capital project costs. 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. As discussed above in "Natural Gas Matters – Disallowed Capital Costs" and Note 14 of the Notes to the Consolidated Financial Statements, the Utility recorded charges of \$196 million and \$353 million in 2013 and 2012, respectively, for PSEP capital costs that are expected to exceed the amount to be recovered. The additional charge in 2013 primarily reflects changes in the project portfolio involving higher costs to replace pipelines than originally forecast. 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 MGP 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 MGP 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, 2013 and 2012, the Utility's accruals for undiscounted gross environmental liabilities were \$900 million and \$910 million, respectively. The Utility's undiscounted future costs could increase to as much as \$1.7 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 minimum amount, 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 "Natural Gas Matters" and "Legal and Regulatory Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements.)

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. A legal obligation can arise from an existing or enacted law, statute, or ordinance; a written or oral contract; or under the legal doctrine of promissory estoppel.

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.

Most of PG&E Corporation's and the Utility's AROs relate to the Utility's obligation to decommission its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission assets. The Utility estimates its obligation for the future decommissioning of its nuclear generation facilities and certain fossil fuel-fired generation facilities. In December 2012, the Utility submitted an updated estimate of the cost to decommission its nuclear facilities to the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by \$1.4 billion in 2012 due to higher spent nuclear fuel disposal costs and an increase in the scope of work. To estimate the 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. (See Note 2 of the Notes to the Consolidated Financial Statements.)

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 4.21%. Similarly, an increase in the discount rate by 25 basis points would decrease the amount of the ARO by 5.24%. At December 31, 2013, the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was \$3.5 billion.

Pension and Other Postretirement Benefit Plans

PG&E Corporation and the Utility provide 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.

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.

PG&E Corporation and the Utility recognize the funded status of their respective plans on their respective Consolidated Balance Sheets with an offsetting entry to accumulated other comprehensive income (loss); or, to the extent that the cost of the plans are recoverable in utility rates, to regulatory assets and liabilities, resulting in no impact to their respective Consolidated Statements of Income.

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.)

PG&E Corporation and the Utility review recent cost trends and projected future trends in establishing health care cost trend rates. 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 2013 is 8%, gradually decreasing to the ultimate trend rate of 5% in 2020 and beyond.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit 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 estimated 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 6.5% compares to a ten-year actual return of 8.7%.

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 494 Aa-grade non-callable bonds at December 31, 2013. 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 2013 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2013
Discount rate	(0.50) %	\$ 122	\$ 1,041
Rate of return on plan assets	(0.50) %	60	-
Rate of increase in compensation	0.50%	60	246

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 2013 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2013
Health care cost trend rate	0.50%	\$ 7	\$ 43
Discount rate	(0.50) %	7	104
Rate of return on plan assets	(0.50) %	9	-

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This 2013 Annual Report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations; forecasts of costs the Utility will incur to make safety and reliability improvements, including natural gas transmission costs that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. 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:

- when and how the pending CPUC investigations and enforcement matters related to the Utility's natural gas system operating practices and the San Bruno accident are concluded, including the ultimate amount of fines the Utility will be required to pay to the State General Fund, the amount of natural gas transmission costs the Utility will be prohibited from recovering, and the cost of any remedial actions the Utility may be ordered to perform;
- the outcome of the pending federal criminal investigation related to the San Bruno accident, including the ultimate amount of civil or criminal fines or penalties, if any, the Utility may be required to pay, and the impact of remedial measures the Utility is required to take such as the appointment of an independent monitor;
- whether PG&E Corporation and the Utility are able to repair the reputational harm that they have suffered, and may suffer in the future, due to the negative publicity surrounding the San Bruno accident and the decisions to be issued in the pending investigations, including any charge or finding of criminal liability;
- the outcomes of ratemaking proceedings, such as the 2014 GRC, the 2015 GT&S rate case, and the TO rate cases;
- the amount and timing of additional common stock 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 outcome of future regulatory investigations, citations, or other proceedings, that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to the operation, inspection, and maintenance of its electric and gas facilities;
- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation 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 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 carbon dioxide 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;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in the Utility's service area, general and regional economic and financial market conditions, the extent of municipalization of the Utility's electric or gas distribution facilities, changing levels of "direct access" customers who procure electricity from alternative energy providers, changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators," and the development of alternative energy technologies including self-generation, storage and distributed generation technologies;
- the adequacy and price of electricity, natural gas, and nuclear fuel supplies; 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 energy commodity costs through rates;

- 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 confidential customer, vendor, and financial data 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 outcome of the pending investigations relating to the Utility’s natural gas operations affects 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, or regulations; 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 “Risk Factors” below. 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.

RISK FACTORS

PG&E Corporation's and the Utility's reputations have been significantly affected by the negative publicity about the San Bruno accident, the related investigations and civil litigation, the Utility's noncompliance with certain natural gas regulations, and the fines imposed on the Utility for noncompliance with these regulations and for violation of certain CPUC rules. Their reputations may be further adversely affected by publicity regarding developments in the pending CPUC and criminal investigations, and by future investigations or other regulatory or governmental proceedings or action that may be commenced. In addition, the Utility's electricity and natural gas operations generally are subject to continuous public scrutiny and criticism that could lead to further reputational harm. Additional reputational harm or the inability of PG&E Corporation and the Utility to restore their reputations may further affect their financial conditions, results of operations and cash flows.

The reputations of PG&E Corporation and the Utility have seriously suffered as a result of the extensive media coverage of the San Bruno accident, the investigative findings from the NTSB and the CPUC's independent review panel that placed the blame for the accident primarily on the Utility, the ensuing civil litigation, the criminal investigation, and the CPUC investigations that were commenced to determine whether the Utility violated any laws, rules, regulations or orders relating to safety recordkeeping, pipeline installation, integrity management, or other operational practices. (See "Natural Gas Matters" above.) PG&E Corporation and the Utility anticipate that there will be additional media coverage of future developments in the pending investigations, especially after the final outcomes are determined.

In addition, there could be additional negative publicity as the SED takes action with respect to numerous reports the Utility has submitted to notify the SED about the Utility's noncompliance with certain natural gas regulations. In January 2012, the SED imposed fines of \$16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from \$50,000 to \$8.1 million for self-reported violations. The SED may impose additional fines based on other self-reported violations. The media also has published reports about two orders to show cause that were issued by the CPUC in August 2013 regarding a filing the Utility submitted in July 2013 to correct certain factual errors made in documents submitted in October 2011 that provided support for an order to restore operating pressure on certain pipelines. In December 2013, the Utility was fined \$14.4 million for violating a CPUC rule prohibiting misleading disclosures to the CPUC.

The Utility's reputation can also be affected by media coverage of highly debated public policy issues such as those relating to the Utility's nuclear generation operations and nuclear decommissioning activities; environmental remediation or permitting activities; the accuracy, privacy, and safety of the Utility's information, operating, and billing systems; and the future development of the state-mandated California High Speed Rail project through the Utility's service territory. Media coverage of outages, vandalism, physical attacks on the Utility's facilities (such as the attack on the Metcalf electric substation), gas leaks, accidents causing injury or death, or other operational events, as well as concerns about the risks of terrorist acts, climate change, earthquakes, or a nuclear accident, can also negatively affect the Utility's reputation. These public policy debates and operational concerns have often led to additional adverse media coverage and could later result in investigations or other action by regulators, legislators and law enforcement officials or in lawsuits.

The outcome of pending ratemaking proceedings, such as the GRC and the GT&S rate case, also could affect PG&E Corporation's and the Utility's reputations, with unfavorable regulatory outcomes having a negative reputational effect. Alternatively, PG&E Corporation's or the Utility's unfavorable reputation could have a negative influence on the regulatory decision-making process.

Investors may question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered, resulting in an adverse impact on the market price of PG&E Corporation common stock. The issuance of common stock by PG&E Corporation to fund the Utility's unrecovered costs has materially diluted PG&E Corporation's EPS. Additional share issuances following a declining stock price would cause further dilution. The extent to which PG&E Corporation's and the Utility's reputations can be restored will depend, in part, on the success of the Utility's efforts to improve the safety and reliability of the natural gas system as planned in the Utility's PSEP, whether they can implement the remaining recommendations made by the CPUC's independent review panel and the NTSB, and whether they are able to adequately show regulators, legislators, law enforcement officials, city officials, the media and the public that they have done so. If PG&E Corporation and the Utility are unable to repair their reputations, their financial conditions, results of operations and cash flows may continue to be negatively affected.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the ultimate outcome of the CPUC investigations; the ultimate amount of gas transmission costs that the Utility does not recover through rates; and the ultimate outcome of the criminal investigation, including the amount of penalties imposed and the cost to implement any required action.

As discussed above in the section entitled "Natural Gas Matters – Pending CPUC Investigations and Enforcement Matters," the SED has recommended that the CPUC impose what the SED characterizes as a penalty of \$2.25 billion on the Utility, consisting of a \$300 million fine payable to the State General Fund and \$1.95 billion of non-recoverable costs. If the SED's penalty recommendation is adopted by the CPUC, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about \$4.5 billion and the Utility would incur material charges in addition to the charges already incurred for the probable fines of \$200 million and unrecoverable natural gas transmission costs. Such charges would materially affect PG&E Corporation's and the Utility's financial condition and results of operations and could negatively affect the availability, amount, and timing of future debt and equity issuances by PG&E Corporation and the Utility. Future developments in the criminal investigation arising from the San Bruno accident also could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. (See the sections entitled "Criminal Investigation" under the heading "Natural Gas Matters.")

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows have been materially affected by costs incurred by the Utility to perform work under the PSEP, to undertake other pipeline-related work, and to improve the safety and reliability of its natural gas and electricity operations. The Utility forecasts that it will incur a material amount of unrecoverable natural gas transmission costs in 2014. The Utility's ability to recover natural gas transmission costs in 2015 through 2017 primarily will be determined by the outcome of the Utility's 2015 GT&S rate case.

In December 2012, the CPUC approved most of the Utility's proposed scope and timing of projects to be completed under the Utility's PSEP through 2014, but the CPUC disallowed the Utility's request for rate recovery of a significant portion of forecasted capital costs and expenses. In October 2013, the Utility filed an update application, as ordered by the CPUC, to reflect changes in the scope and priority of projects resulting from the Utility's completed search and review of records related to pipeline pressure validation and other information, including updated cost forecasts. At

December 31, 2013, the Utility had recorded cumulative charges of \$549 million for PSEP capital costs that the Utility expects will exceed the adopted cost amounts. (See “Natural Gas Matters” above.) The Utility could record additional charges for disallowed costs if the CPUC does not approve the Utility’s request to adjust revenue requirements or if cost forecasts increase. The Utility also forecasts it will incur costs during 2014 that it will not recover through rates, including costs to identify and remove encroachments from gas transmission pipeline rights-of-way, to pressure test pipelines placed into service after January 1, 1956, consistent with the CPUC’s disallowance of such costs in the PSEP decision, and remedial costs associated with the Utility’s pipeline corrosion control program.

The Utility's ability to recover its natural gas transmission and storage costs in 2015, 2016, and 2017, will be determined by whether the CPUC approves the Utility's GT&S rate case application. (See "Regulatory Matters" above.) PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected if the CPUC does not approve the Utility's request or if actual costs exceed the capital and expense amounts that the CPUC may authorize. The Utility has not requested rate recovery for certain costs it forecasts it will incur during 2015 through 2017, including costs to identify and remove encroachments from gas transmission pipeline rights-of-way, to pressure test certain pipelines, and to take remedial measures to address pipeline corrosion. 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's ability to recover natural gas transmission costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.

The Utility relies on access to capital and credit markets as significant sources of liquidity to fund capital expenditures, pay principal and interest on its debt, provide collateral to support its natural gas and electricity procurement hedging contracts, and fund other operations requirements that are not satisfied by operating cash flows. See the discussion of the Utility's future financing needs above in "Liquidity and Financial Resources." The Utility's financing needs would increase if the Utility were required to incur unrecoverable costs and pay fines as a result of the outcome of the pending investigations discussed in "Natural Gas Matters" above. Such financing may become more difficult to obtain, especially if the ultimate outcome of the investigations affected the Utility's credit ratings. As the Utility has incurred costs it has been unable to recover through rates, it has relied on equity contributions from PG&E Corporation to maintain the 52% equity component of its CPUC-authorized capital structure. The Utility's equity needs could increase materially depending on the ultimate outcome of the pending investigations and the amount of natural gas and transmission costs it is unable to recover through rates.

PG&E Corporation relies on independent access to the capital and credit markets to fund its operations, make capital expenditures, and contribute equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure, if funds received from the Utility (in the form of dividends or share repurchases) are insufficient to meet such needs. Since the San Bruno accident, PG&E Corporation has issued a material amount of equity to fund its equity contributions to the Utility. PG&E Corporation forecasts that it will need to issue additional material amounts of equity in 2014 as the Utility continues to incur costs that it cannot recover through rates. If the Utility is required to pay penalties in an amount that exceeds the amount already accrued, the Utility may need further equity contributions that PG&E Corporation may need to fund through additional dilutive share issuances. PG&E Corporation also may be required to access the capital markets to fund equity contributions to the Utility following the Utility's issuance of long-term debt to maintain the Utility's capital structure. PG&E Corporation primarily has relied on the public sale of its common stock to raise the funds it contributes to meet the Utility's equity needs. The market price of PG&E Corporation common stock could decline materially depending on the outcome of the investigations and the amount and timing of future share issuances. Declines in the stock price could increase the dilutive effect of future stock issuances and make it more difficult or expensive for PG&E Corporation to complete future equity offerings.

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 pending investigations, the outcome of pending ratemaking proceedings, changes in their credit ratings, 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. 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.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing 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 and the Utility's financial condition depends upon the Utility's ability to recover its operating expenses and its electricity and natural gas procurement costs and to earn a reasonable rate of return on capital investments, in a timely manner from the Utility's customers through regulated rates.

The Utility's ability to recover its costs and earn its authorized rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers' rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. (See "Regulatory Matters – 2014 General Rate Case" above.) The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. For example, the CPUC has prohibited the Utility from recovering a material portion of costs that the Utility has already incurred, and will continue to incur, as it performs work under the PSEP, in part, because the CPUC found that such costs were incurred as a result of imprudent management. The CPUC may order the Utility to propose cost-sharing methods for certain costs or the Utility may decide for other reasons not to seek recovery of certain costs. In either case, the Utility would incur costs that are not recovered through rates. (See "Natural Gas Matters" above.)

Further, to serve its customers in a safe and reliable manner, the Utility may be required to incur expenses before the CPUC approves the recovery of such costs. The Utility is generally unable to recover costs incurred before CPUC authorization is obtained, unless the CPUC authorizes the Utility to track costs for potential future recovery. For example, the Utility requested that the CPUC allow the Utility to track costs incurred in 2012 under the PSEP before the CPUC approved the plan. The CPUC did not address the Utility's request and as a result the Utility was unable to recover costs incurred before the effective date of the decision, December 20, 2012. The Utility's failure to recover these and other pipeline-related costs has materially affected PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

Changes in laws and regulations or changes in the political and regulatory environment also may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. In addition, the Utility may be required to incur substantial costs to comply with new state laws or to implement new state policies before the Utility is assured of cost recovery. For example, the state-mandated development of the

California High Speed Rail Project through the Utility's service territory will require the relocation of some of the Utility's electric and gas facilities, new electric facilities, and significant expansion and upgrade to the Utility's electric system. Although the CPUC has begun a proceeding to address cost allocation and cost recovery issues, the Utility may incur costs before the issues are settled, for example, to obtain environmental permits. Further, fluctuating commodity prices also could affect the Utility's ability to timely recover its costs and earn its authorized rate of return. Although current law and regulatory mechanisms permit the Utility to pass through its costs to procure electricity and natural gas to customers in rates, a significant and sustained rise in commodity prices, caused by costs associated with new renewable energy resources and California's new cap-and-trade program and other factors, could create overall rate pressures that make it more difficult for the Utility to recover its costs. This pressure could increase as the Utility continues to collect authorized rates to support public purpose programs, such as energy efficiency programs, and low-income rate subsidies, and to fund customer incentive programs.

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. 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. A portion of the Utility's revenues depends on the level of customer demand for the Utility's natural gas transportation services which can fluctuate based on economic conditions, the price of natural gas, and other factors. In the GT&S rate case application, the Utility has proposed that this revenue mechanism be eliminated beginning on January 1, 2015 but it is uncertain whether the request will be granted.

The Utility's failure to recover its operating expenses, including electricity and natural gas procurement costs in a timely manner through rates could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

The Utility's ability to procure electricity to meet customer demand at reasonable prices and recover procurement-related costs timely may be affected by increasing renewable energy requirements, the continuing functioning of the wholesale electricity market in California, and the expanded cap-and-trade market.

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."

Following competitive requests for offers from third parties, the Utility enters into power purchase agreements, including contracts to purchase renewable energy, in compliance with a CPUC-approved long-term procurement plan. These agreements become binding obligations of the Utility after the CPUC approves the agreements and authorizes the Utility to recover contract costs through rates. There is a risk that the contractual prices the Utility is required to pay will 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 economic conditions or the loss of the Utility's customers to other generation providers. In particular, as the market for renewable energy develops in response to California's renewable energy requirements, there is a risk that the Utility's contractual commitments could result in procurement costs that are higher than the market price of renewable energy. This could create a further risk that, despite original CPUC approval of the contracts, the CPUC would disallow contract costs in the future if the CPUC determines that the costs are unreasonably above market. In addition, the CPUC could disallow procurement costs if the CPUC determined that the Utility incurred procurement costs that were not in compliance with its CPUC-approved procurement plan, or that the Utility did not prudently administer the power purchase agreements that were executed in compliance with the plan. The Utility also could incur liability 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 costs incurred by the Utility under these circumstances would be subject to reasonableness review by the CPUC and could be disallowed.

The Utility also purchases energy through the day-ahead and real-time wholesale electricity market operated by the CAISO. The amount of electricity the Utility purchases on the wholesale market fluctuates due to a variety of factors, including, the level of electricity generated by the Utility's own generation facilities, changes in customer demand, periodic expirations or terminations of power purchase contracts, the execution of new power purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, and the implementation of new energy efficiency and demand response programs. The market prices of electricity also fluctuate due to various factors, including the type of generation resources. Hydroelectric generation resources are generally the least expensive. As drought conditions in California and the Western U.S. persist, the market prices of electricity will generally reflect the higher cost of conventional and other resources. 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 due to a cyber-attack or other reason, which could result in excessive market prices. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's 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.

In addition, electricity costs include the costs to comply with California's cap-and-trade regulations. Although some of these costs can be offset by revenues from the sale of emission allowances by the Utility on behalf of some classes of electricity customers, it is uncertain how the cap-and-trade market will develop in the future especially as the cap-and-trade compliance periods expand to cover other sources of GHG emissions and as other regional or federal cap-and-trade programs are adopted.

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected if the Utility is unable to recover a material portion of the costs it incurs to deliver electricity to customers.

The completion of capital investment projects is subject to substantial risks, and the timing of the Utility's capital expenditures and recovery of capital-related costs through rates, if at all, will directly affect net income.

The Utility's ability to invest capital in its electric and natural gas businesses is subject to many risks, including risks related to obtaining regulatory approval, securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop or construct these projects also face many of these risks. Changes in tax laws or policies, such as those relating to "bonus" depreciation, may also affect when or whether a potential project is developed. In addition, reduced forecasted demand for electricity and natural gas as a result of an economic slow-down, or other reasons, may also increase the risk that projects are deferred, abandoned, or cancelled. Some of the Utility's future capital investments may also be affected by evolving federal and state policies regarding the development of a "smart" electric transmission grid.

In addition, differences in the amount or timing of actual capital expenditures compared to the amount and timing of forecast capital expenditures authorized to be recovered through rates, can directly affect net income. Changes in regulatory policies concerning ongoing recovery of costs for existing projects may increase risks associated with capital investment. Further, if capital expenditures are disallowed, the Utility would be required to write-off such expenses which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations. For example, at December 31, 2013, the Utility had recorded cumulative charges of \$549 million for PSEP capital costs that the CPUC has

specifically disallowed and for increases in the amount of costs that the Utility forecasts will exceed the adopted cost amounts.

PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth due to municipalization, an increase in the number of community choice aggregators, increasing levels of "direct access," and the development and integration of self-generation and distributed generation technologies, if the CPUC fails to adjust the Utility's rates to reflect such events.

The Utility's customers could bypass its distribution and transmission system by obtaining such services from other providers. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers. In addition, local government agencies could exercise their power of eminent domain to acquire the Utility's facilities and use the facilities to provide utility service to their local residents and businesses. The Utility may be unable to fully recover its investment in the distribution assets that it no longer owns. The Utility's natural gas transmission facilities could be bypassed by interstate pipeline companies that construct facilities in the Utility's markets, by customers who build pipeline connections that bypass the Utility's natural gas transmission and distribution system, or by customers who use and transport liquefied natural gas.

Alternatively, the Utility's customers could become direct access customers who purchase electricity from alternative energy suppliers or they could become customers of governmental bodies registered as community choice aggregators to purchase and sell electricity for their residents and businesses. Although the Utility is permitted to collect a non-bypassable charge for generation-related costs incurred on behalf of these customers, or distribution, metering, or other services it continues to provide, the fee may not be sufficient for the Utility to fully recover the costs to provide these services. 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 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 CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, increasing self-generation and net energy metering, and the growth of distributed generation and storage, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

The operation of the Utility's electricity and natural gas generation, transmission, and distribution facilities involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations and cash flows, 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. The Utility's service territory covers approximately 70,000 square miles in northern and central California and is composed of diverse geographic regions with varying climates, weather conditions, vegetation amounts, and population density levels, all of which create numerous operating challenges. The Utility's facilities are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. These facilities are subject to physical attacks, including cyber-attacks that can cause local or widespread outages of electric or natural gas service, or otherwise disrupt operations, as well as cause property damage and personal injury. The Utility and other industry participants implement various security measures to monitor and protect their facilities but these security measures may not always be successful. The Utility's ability to earn its authorized rate of return depends on its ability to efficiently maintain, operate, and protect its facilities and provide electricity and natural gas services safely and reliably. The maintenance and operation of the Utility's facilities, and the facilities of third parties on which the Utility relies, involve numerous risks, including the risks discussed elsewhere in this section and 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;
- the failure of generation facilities to perform at expected or at contracted levels of output or efficiency;
- 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 electric transmission 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, and the failure to respond effectively to a catastrophic event;
- severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wildland 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 that damages the Utility's underground facilities;
- fuel supply interruptions or the lack of available fuel which reduces or eliminates the Utility's ability to provide electricity and/or natural gas service;
- the release of hazardous or toxic substances into the air or water;

- use of new or unproven technologies;
- attacks by third parties, including cyber-attacks; and
- acts of terrorism, vandalism, or war.

The occurrence of any of these events could affect demand for electricity or natural gas; cause unplanned outages or reduce generating output which may require the Utility to incur costs to purchase replacement power; cause damage to the Utility's assets or operations requiring the Utility to incur unplanned expenses to respond to emergencies and make repairs; damage the assets or operations of third parties on which the Utility relies; subject the Utility to claims by customers or third parties for damages to property, personal injury, or wrongful death, or subject the Utility to penalties. These costs may not be recoverable through rates or insurance. Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of 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 condition, results of operations, and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage or may not be available at all.

The Utility's operational and information systems on which it relies to conduct its business and serve customers could fail to function properly due to technological problems, cyber-attacks, physical attacks on the Utility's assets, acts of terrorism, severe weather, solar events, electromagnetic events, natural disasters, the age and condition of information technology assets, human error, or other reasons, that could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense.

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 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. 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 to 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 condition, results of operations, and cash flows.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require constant maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. 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 companies' control environment, and/or the companies' ability to timely file required regulatory reports.

The Utility's ability to measure customer energy usage and generate bills depends on the successful functioning of the advanced metering system. The Utility relies on third party contractors and vendors to service, support, and maintain certain proprietary functional components of the advanced metering system. If such a vendor or contractor ceased operations, if there was a contractual dispute or a failure to renew or negotiate the terms of a contract so that the Utility becomes unable to continue relying on such a third-party vendor or contractor, then the Utility could experience costs associated with disruption of billing and measurement operations and would incur costs as it seeks to find other replacement contractors or vendors or hire and train personnel to perform such services.

Despite implementation of security and mitigation measures, all of the Utility's technology systems are vulnerable to disability or failures due to cyber-attacks, physical attacks on the facilities and equipment needed to operate the technology systems, viruses, human errors, acts of war or terrorism, and other events. If the Utility's information technology systems or network infrastructure were to fail, the Utility might be unable to fulfill critical business functions and serve its customers, which could have a material effect on PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

In addition, in the ordinary course of its business, the Utility collects and retains sensitive information including personal identification information about customers and employees, customer energy usage, and other confidential information. The theft, damage, or improper disclosure of sensitive electronic data can subject the Utility to penalties for violation of applicable privacy laws, subject the Utility to claims from third parties, and harm the Utility's reputation.

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 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 not be successful. 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. The terms of these agreements affect the Utility's labor costs. It is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future. It is also possible that PG&E Corporation and the Utility 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 San Bruno accident. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities that it may not be able to recover from its insurance or other sources, and the Utility may incur significant capital expenditures and compliance costs that it may be unable to fully recover, adversely affecting PG&E Corporation's and the Utility's financial conditions, results of operations, and cash flows.

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. There are also significant uncertainties related to the regulatory, technological, and financial aspects of decommissioning nuclear generation plants when their licenses expire. To reduce the Utility's financial exposure to these risks, the Utility maintains insurance and manages decommissioning trusts that hold nuclear decommissioning charges collected through customer rates. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of its nuclear power plants could exceed the amount of the Utility's insurance coverage and nuclear decommissioning trust assets. The Utility has insurance coverage for property damages and business interruption losses, as well as coverage for acts of terrorism at its nuclear power plants as a member of NEIL, a mutual insurer owned by utilities with nuclear facilities. NEIL provides coverage for both nuclear (meaning that nuclear material is released) and non-nuclear losses. Due to multiple large non-nuclear losses in the industry, in 2013 NEIL significantly reduced its coverage for non-nuclear losses. While the Utility is seeking alternative insurance options, efforts to obtain additional coverage may not be successful. Even if the Utility is able to obtain additional coverage, this future insurance coverage may not be available at rates and terms as favorable as the rates and terms of the Utility's current NEIL insurance coverage. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

In addition, as an operator of the two operating nuclear reactor units at Diablo Canyon, 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.) The Utility's ability to continue to operate its nuclear generation facilities also is subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable.

The NRC oversees the licensing, construction, and decommissioning of nuclear facilities and has broad authority to impose requirements relating to the maintenance and operation of nuclear facilities; the storage, handling and disposal of spent fuel; and the safety, radiological, environmental, and security aspects of nuclear facilities. The NRC has adopted regulations that are intended to protect nuclear facilities, nuclear facility employees, and the public from potential terrorist and other threats to the safety and security of nuclear operations, including threats posed by radiological sabotage or cyber-attack. The Utility incurs substantial costs to comply with these regulations. In addition, in March 2012, the NRC issued several orders to the owners of all U.S. operating nuclear reactors to implement the highest-priority recommendations issued by the NRC's task force to incorporate the lessons learned from the March 2011 earthquake and tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan. The NRC may issue further orders to implement the recommendations, including facility-specific orders, which could require the Utility to incur additional costs.

In 2009, the Utility filed an application with the NRC to renew the operating licenses for the two operating units at Diablo Canyon. (See "Regulatory Matters – Diablo Canyon Nuclear Power Plant" above.) In May 2011, after the Fukushima-Dai-ichi event, the NRC granted the Utility's request to delay processing the Utility's application while certain advanced seismic studies were completed. The Utility is currently assessing the data from recently completed advanced seismic studies along with other available seismic data. The Utility will not make any decision about whether to request that the NRC to resume processing the license renewal application until this assessment is completed and provided to the NRC. The Utility anticipates that it will complete this assessment by June 2014. If the Utility does not request that the NRC resume processing the application, the current operating licenses would expire in 2024 and 2025. In any event, the NRC has stated that it will not issue final decisions in licensing or re-licensing proceedings, including the Utility's re-licensing application, until it has issued a new "waste confidence decision," as described below. In addition, the NRC would not issue renewed operating licenses for Diablo Canyon unless the California Coastal Commission determined that license renewal is consistent with federal and state coastal laws.

In the NRC's original "waste confidence decision," the NRC found that spent nuclear fuel can be safely managed until a permanent off-site repository is established. The NRC's waste confidence decision was successfully challenged on the basis that the NRC's environmental review was deficient. The NRC has instructed its staff to develop and issue a new waste confidence decision and temporary storage rule by October 2014. It is uncertain how the new waste confidence decision and temporary storage rule would affect the Utility's decision to resume the renewal application process at the NRC or, if the application process were resumed, how the new waste confidence decision and temporary storage rule would affect the disposition of the renewal application. It is also uncertain how the new waste confidence decision and temporary storage rule would affect the Utility's nuclear generation operations during the current terms of the NRC licenses for Diablo Canyon.

The CPUC has authority to determine the rates the Utility can collect to recover its nuclear fuel, operating, maintenance, compliance, and decommissioning costs. The Utility also could incur significant expense to comply with regulations or orders the NRC may issue in the future to impose new safety requirements, to obtain license renewal, and to comply with federal and state policies and regulations applicable to the use of cooling water intake systems at generation facilities, such as Diablo Canyon. (See "Environmental Matters" above.) The Utility expects that it would seek rate recovery of these additional costs. The outcome of these rate proceedings at the CPUC can be influenced by public and political opposition to nuclear power.

If the Utility were unable to recover costs related to its nuclear facilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders, including a new waste confidence decision, in a feasible and economic manner and voluntarily cease operations at Diablo Canyon. Alternatively, the NRC may order the Utility to cease its nuclear operations until it can comply with new regulations, orders, or decisions. Further, the Utility could decide not to resume the license renewal process or the Utility could fail to obtain renewed operating licenses for Diablo Canyon requiring nuclear operations to cease when the current licenses expire in 2024 and 2025.

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 conditions, results of operations, and cash flows.

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 can incur significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. These costs can be difficult to forecast because the extent of contamination may be unknown. For example, the Utility's costs to perform hydrostatic pressure tests on natural gas pipelines were higher than anticipated because the water used to perform the tests became contaminated as it traveled through the pipe and the Utility had to incur additional costs to remediate the contaminated wastewater. Further, even if the extent of contamination is known, remediation costs can be difficult to estimate due to many factors, including which remediation alternatives will be used, the applicable remediation levels, and the financial ability of other potentially responsible parties. 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 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. These sites, some of which the Utility no longer owns, include former manufactured gas plant sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. 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. Although the Utility has liabilities 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. (See Note 14 to the Notes to the Consolidated Financial Statements for more information.)

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. 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 conditions, results of operations, and cash flows. (See "Environmental Matters" above.)

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.

A report issued in 2012 by the EPA entitled, "Climate Change Indicators in the United States, 2012" states that the increase of GHG emissions in the atmosphere is changing the fundamental measures of climate in the United States, including rising temperatures, shifting snow and rainfall patterns, and more extreme climate events. In December 2009, the EPA issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. The impact of events or conditions caused by climate change could range widely, from highly localized to worldwide, and the extent to which the Utility's operations may be affected is uncertain. For example, if reduced snowpack decreases the Utility's hydroelectric generation, the Utility will need to acquire additional generation from other sources at a greater cost. In addition, if lower hydroelectric generation due to dry conditions or prolonged drought increases reliance on conventional generation resources, it may be more costly for the Utility to comply with California's renewable portfolio standard program and GHG emissions limits.

Under certain circumstances, the events or conditions caused by climate change could result in a full or partial disruption of the ability of the Utility – or one or more of the entities on which it relies – to generate, transmit, transport, or distribute electricity or natural gas. The Utility has been studying the potential effects of climate change on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. 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.

The Utility is subject to fines and penalties for failure to comply with federal, state, or local statutes and regulations. Changes in the political and regulatory environment could cause federal and state statutes, regulations, rules, and orders to become more stringent and difficult to comply with, and required permits, authorizations, and licenses may be more difficult to obtain, increasing the Utility's expenses or making it more difficult for the Utility to execute its business strategy.

The Utility must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. In addition to the NRC requirements described above, these include meeting new renewable energy delivery requirements, resource adequacy requirements, federal electric reliability standards, customer billing, customer service, affiliate transactions, vegetation management, operating and maintenance practices, and safety and inspection practices. The Utility is subject to penalties and sanctions for failure to comply with applicable statutes, regulations, rules, tariffs, and orders.

The CPUC can impose fines up to \$50,000 per day, per violation. The CPUC has wide discretion to determine, based on the facts and circumstances, whether a single violation or multiple violations were committed and to determine the length of time a violation existed for purposes of calculating the amount of fines. The CPUC has delegated authority to the SED to levy citations and impose fines for violations of certain regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. Like the CPUC, the SED has discretion to determine how to count the number of violations, but the delegated authority requires the SED to assess the maximum statutory fine per violation with discretion to adjust the amount of the fine based on the risk-level of the violation as determined by the SED. (For a discussion of pending investigations and potential enforcement proceedings, see MD&A "Natural Gas Matters" above.) A California law enacted in 2013 requires the CPUC to establish a safety enforcement program for gas facilities by July 1, 2014 and for electric facilities by January 1, 2015. The law requires the CPUC to delegate enforcement authority to the SED under these programs. The CPUC may make changes to its gas safety enforcement program to implement the new law. These programs may increase the risk that penalties will be imposed on the Utility.

In addition, the federal Pipeline and Hazardous Materials Safety Administration has independent authority to impose fines for violation of federal pipeline safety regulations in amounts that range from \$100,000 to \$200,000 for an individual violation and from \$1 million to \$2 million for a series of violations.

The Utility must comply with federal electric reliability standards that are set by the North American Electric Reliability Corporation and approved by the FERC. These standards relate to maintenance, training, operations, planning, vegetation management, facility ratings, and other subjects. These standards are designed to maintain the reliability of the nation's bulk power system and to protect the system against potential disruptions from cyber-attacks and physical security breaches. Regulatory authorities conduct frequent compliance audits of the Utility's operating practices. The FERC can impose fines (up to \$1 million per day, per violation) for failure to comply with these mandatory electric reliability standards. As these and other standards and rules evolve, and as the wholesale electricity markets become more complex, the Utility's risk of noncompliance may increase.

In addition, statutes, regulations, rules, tariffs, and orders, or their interpretation and application, may become more stringent and difficult to comply with in the future. If this occurs, the Utility could be exposed to increased costs to comply with the more stringent requirements or new interpretations and to potential liability for customer refunds, penalties, or other amounts. If it is determined that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially affected.

The Utility also must comply with the terms of various governmental permits, authorizations, and licenses. These permits, authorizations, and licenses may 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, waste discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. 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.

If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, or licenses, or if the Utility cannot recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially affected.

Market performance or changes in other assumptions 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. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. 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 the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation, and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by 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. Funding requirements also can be affected by the difference between the actual rate of return on plan assets and the assumed rate and by changes in the assumed rate of return. For example, changes in interest rates affect the liabilities under the plans: as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

The Utility has recorded an asset retirement obligation related to decommissioning its nuclear facilities based on various estimates and assumptions. Changes in these estimates and assumptions can materially affect the amount of the recorded asset retirement obligation. (See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the increase in the recorded asset retirement obligation to reflect increased estimated decommissioning costs.)

The CPUC has authorized the Utility to recover forecasted costs to fund pension and postretirement plan contributions and nuclear decommissioning through rates. If the Utility is required to make significant unplanned contributions to fund the pension and postretirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities also can negatively affect net income.

PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions, and values and are prepared in accordance with applicable accounting rules, standards, policies, guidance, and interpretations, including those related to regulatory assets and liabilities. Changes to these estimates, assumptions, values, and accounting rules, or changes in the application of these rules, could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets, and liabilities, and the disclosure of contingencies. (See the discussion under Notes 1 and 2 of the Notes to the Consolidated Financial Statements and "Critical Accounting Policies" above.) If the information on which the estimates and assumptions are based proves to be incorrect or incomplete, if future events do not occur as anticipated, or if there are changes in applicable accounting guidance, policies, or interpretation, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions, or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation's and the Utility's financial condition or results of operations.

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility's continued use of regulatory accounting (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) depends on its ability to recover its cost of service. (See Note 3 of the Notes to the Consolidated Financial Statements.) Since the San Bruno accident, the Utility has recorded cumulative charges of approximately \$2.5 billion related to its natural gas operations that are not recoverable through rates. (See "Natural Gas Matters" above.) To the extent that rates, including rates in the 2015 GT&S rate case, are not set at a level that allows the Utility to recover the cost of providing service and a reasonable return on its investment in future periods, the Utility may be required to discontinue the application of regulatory accounting for portions of its operations. If that occurs, the related regulatory assets and liabilities would be charged against income in the period in which that determination was made and could have a material impact on PG&E Corporation's and the Utility's future financial condition and results of operations. In addition, if regulatory accounting did not apply, the Utility's future financial results could become more volatile under GAAP accounting as compared to historical financial results under regulatory accounting due to the differences in the timing of expense (or gain) recognition under GAAP accounting as compared to regulatory accounting.

As a holding company, PG&E Corporation depends on cash distributions and reimbursements from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its outstanding debt, the principal at maturity, and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, 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. The Utility's ability to pay common stock dividends is constrained by regulatory requirements, including that the Utility maintain its authorized capital structure with an average 52% equity component. 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%. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted. (Also see the discussion of financing risks above.)

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, including an obligation by 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. The CPUC later issued decisions adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The Utility's financial condition will be affected by the amount of costs the Utility incurs that it does not recover through rates (whether such non-recovery is because actual costs exceed authorized or forecast costs, the Utility did not seek authorization to recover certain costs, or the CPUC prohibited the Utility from recovering certain costs), the amount of third-party losses it is unable to recover through insurance, and the amount of penalties the Utility incurs in connection with the pending investigations and future citations for self-reported violations. After considering these impacts, the CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future or could prevent distributions from the Utility to PG&E Corporation, or both, any of which could materially restrict PG&E Corporation's ability to pay principal and interest on its outstanding debt or pay its common stock dividend, meet other obligations, or execute its business strategy. Further, laws or regulations could be enacted or adopted in the future that could impose additional financial or other restrictions or requirements pertaining to transactions between a holding company and its regulated subsidiaries.

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

	Year ended December 31,		
	2013	2012	2011
Operating Revenues			
Electric	\$ 12,494	\$ 12,019	\$ 11,606
Natural gas	3,104	3,021	3,350
Total operating revenues	15,598	15,040	14,956
Operating Expenses			
Cost of electricity	5,016	4,162	4,016
Cost of natural gas	968	861	1,317
Operating and maintenance	5,775	6,052	5,466
Depreciation, amortization, and decommissioning	2,077	2,272	2,215
Total operating expenses	13,836	13,347	13,014
Operating Income	1,762	1,693	1,942
Interest income	9	7	7
Interest expense	(715)	(703)	(700)
Other income, net	40	70	49
Income Before Income Taxes	1,096	1,067	1,298
Income tax provision	268	237	440
Net Income	828	830	858
Preferred stock dividend requirement of subsidiary	14	14	14
Income Available for Common Shareholders	\$ 814	\$ 816	\$ 844
Weighted Average Common Shares Outstanding, Basic	444	424	401
Weighted Average Common Shares Outstanding, Diluted	445	425	402
Net Earnings Per Common Share, Basic	\$ 1.83	\$ 1.92	\$ 2.10
Net Earnings Per Common Share, Diluted	\$ 1.83	\$ 1.92	\$ 2.10

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	Year ended December 31,		
	2013	2012	2011
Net Income	\$ 828	\$ 830	\$ 858
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations (net of taxes of \$80, \$72, and \$9, at respective dates)	113	108	(11)
Gain on investments (net of taxes of \$26, \$3, and \$0, at respective dates)	38	4	-
Total other comprehensive income (loss)	151	112	(11)
Comprehensive Income	979	942	847
Preferred stock dividend requirement of subsidiary	14	14	14
Comprehensive Income Attributable to Common Shareholders	\$ 965	\$ 928	\$ 833

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 296	\$ 401
Restricted cash	301	330
Accounts receivable		
Customers (net of allowance for doubtful accounts of \$80 and \$87 at December 31, 2013 and 2012, respectively)	1,091	937
Accrued unbilled revenue	766	761
Regulatory balancing accounts	1,124	936
Other	312	365
Regulatory assets	448	564
Inventories		
Gas stored underground and fuel oil	137	135
Materials and supplies	317	309
Income taxes receivable	574	211
Other	611	172
Total current assets	5,977	5,121
Property, Plant, and Equipment		
Electric	42,881	39,701
Gas	14,379	12,571
Construction work in progress	1,834	1,894
Other	2	1
Total property, plant, and equipment	59,096	54,167
Accumulated depreciation	(17,844)	(16,644)
Net property, plant, and equipment	41,252	37,523
Other Noncurrent Assets		
Regulatory assets	4,913	6,809
Nuclear decommissioning trusts	2,342	2,161
Income taxes receivable	85	176
Other	1,036	659
Total other noncurrent assets	8,376	9,805
TOTAL ASSETS	\$ 55,605	\$ 52,449

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2013	2012
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,174	\$ 492
Long-term debt, classified as current	889	400
Accounts payable		
Trade creditors	1,293	1,241
Disputed claims and customer refunds	154	157
Regulatory balancing accounts	1,008	634
Other	471	444
Interest payable	892	870
Other	1,612	2,018
Total current liabilities	7,493	6,256
Noncurrent Liabilities		
Long-term debt	12,717	12,517
Regulatory liabilities	5,660	5,088
Pension and other postretirement benefits	1,601	3,575
Asset retirement obligations	3,539	2,919
Deferred income taxes	7,823	6,748
Other	2,178	2,020
Total noncurrent liabilities	33,518	32,867
Commitments and Contingencies (Note 14)		
Equity		
Shareholders' Equity		
Preferred stock	-	-
Common stock, no par value, authorized 800,000,000 shares, 456,670,424 shares outstanding at December 31, 2013 and 430,718,293 shares outstanding at December 31, 2012	9,550	8,428
Reinvested earnings	4,742	4,747
Accumulated other comprehensive income (loss)	50	(101)
Total shareholders' equity	14,342	13,074
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	14,594	13,326
TOTAL LIABILITIES AND EQUITY	\$ 55,605	\$ 52,449

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2013	2012	2011
Cash Flows from Operating Activities			
Net income	\$ 828	\$ 830	\$ 858
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,077	2,272	2,215
Allowance for equity funds used during construction	(101)	(107)	(87)
Deferred income taxes and tax credits, net	1,075	648	544
PSEP disallowed capital expenditures	196	353	-
Other	355	290	326
Effect of changes in operating assets and liabilities:			
Accounts receivable	(152)	(40)	(288)
Inventories	(10)	(24)	(63)
Accounts payable	113	(4)	65
Income taxes receivable/payable	(363)	(132)	(103)
Other current assets and liabilities	(469)	262	23
Regulatory assets, liabilities, and balancing accounts, net	(202)	291	(100)
Other noncurrent assets and liabilities	80	243	349
Net cash provided by operating activities	3,427	4,882	3,739
Cash Flows from Investing Activities			
Capital expenditures	(5,207)	(4,624)	(4,038)
Decrease in restricted cash	29	50	200
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,619	1,133	1,928
Purchases of nuclear decommissioning trust investments	(1,604)	(1,189)	(1,963)
Other	56	104	(113)
Net cash used in investing activities	(5,107)	(4,526)	(3,986)
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	140	120	358
Repayments under revolving credit facilities	-	-	(358)
Net issuances (repayments) of commercial paper, net of discount of \$2, \$3, and \$4 at respective dates	542	(1,021)	782
Proceeds from issuance of short-term debt	-	-	250
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$18, \$13, and \$8 at respective dates	1,532	1,137	792
Short-term debt matured	-	(250)	(250)
Long-term debt matured or repurchased	(861)	(50)	(700)
Energy recovery bonds matured	-	(423)	(404)
Common stock issued	1,045	751	662
Common stock dividends paid	(782)	(746)	(704)
Other	(41)	14	41
Net cash provided by (used in) financing activities	1,575	(468)	469
Net change in cash and cash equivalents	(105)	(112)	222
Cash and cash equivalents at January 1	401	513	291
Cash and cash equivalents at December 31	\$ 296	\$ 401	\$ 513
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	\$ (623)	\$ (594)	\$ (647)
Income taxes, net	(41)	114	(42)
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	\$ 208	\$ 196	\$ 188
Capital expenditures financed through accounts payable	322	362	308
Noncash common stock issuances	22	22	24
Terminated capital leases	-	136	-

See accompanying Notes to the Consolidated Financial Statements.

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

	Common Stock Shares	Common Stock Amount	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Non controlling Interest - Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2010	395,227,205	\$ 6,878	\$ 4,606	\$ (202)	\$ 11,282	\$ 252	\$ 11,534
Net income	-	-	858	-	858	-	858
Other comprehensive loss	-	-	-	(11)	(11)	-	(11)
Common stock issued, net	17,029,877	686	-	-	686	-	686
Stock-based compensation amortization	-	37	-	-	37	-	37
Common stock dividends declared	-	-	(738)	-	(738)	-	(738)
Tax benefit from employee stock plans	-	1	-	-	1	-	1
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2011	412,257,082	7,602	4,712	(213)	12,101	252	12,353
Net income	-	-	830	-	830	-	830
Other comprehensive income	-	-	-	112	112	-	112
Common stock issued, net	18,461,211	773	-	-	773	-	773
Stock-based compensation amortization	-	52	-	-	52	-	52
Common stock dividends declared	-	-	(781)	-	(781)	-	(781)
Tax benefit from employee stock plans	-	1	-	-	1	-	1
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2012	430,718,293	\$ 8,428	\$ 4,747	\$ (101)	\$ 13,074	\$ 252	\$ 13,326
Net income	-	-	828	-	828	-	828
Other comprehensive income	-	-	-	151	151	-	151
Common stock issued, net	25,952,131	1,067	-	-	1,067	-	1,067
Stock-based compensation amortization	-	56	-	-	56	-	56
Common stock dividends declared	-	-	(819)	-	(819)	-	(819)
Tax expense from employee stock plans	-	(1)	-	-	(1)	-	(1)
Preferred stock dividend requirement of subsidiary	-	-	(14)	-	(14)	-	(14)
Balance at December 31, 2013	<u>456,670,424</u>	<u>\$ 9,550</u>	<u>\$ 4,742</u>	<u>\$ 50</u>	<u>\$ 14,342</u>	<u>\$ 252</u>	<u>\$ 14,594</u>

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2013	2012	2011
Operating Revenues			
Electric	\$ 12,489	\$ 12,014	\$ 11,601
Natural gas	3,104	3,021	3,350
Total operating revenues	15,593	15,035	14,951
Operating Expenses			
Cost of electricity	5,016	4,162	4,016
Cost of natural gas	968	861	1,317
Operating and maintenance	5,742	6,045	5,459
Depreciation, amortization, and decommissioning	2,077	2,272	2,215
Total operating expenses	13,803	13,340	13,007
Operating Income	1,790	1,695	1,944
Interest income	8	6	5
Interest expense	(690)	(680)	(677)
Other income, net	84	88	53
Income Before Income Taxes	1,192	1,109	1,325
Income tax provision	326	298	480
Net Income	866	811	845
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	\$ 852	\$ 797	\$ 831

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	Year ended December 31,		
	2013	2012	2011
Net Income	\$ 866	\$ 811	\$ 845
Other Comprehensive Income			
Pension and other postretirement benefit plans obligations (net of taxes of \$75, \$73, and \$4, at respective dates)	106	109	(7)
Total other comprehensive income (loss)	106	109	(7)
Comprehensive Income	\$ 972	\$ 920	\$ 838

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 65	\$ 194
Restricted cash	301	330
Accounts receivable		
Customers (net of allowance for doubtful accounts of \$80 and \$87 at December 31, 2013 and 2012, respectively)	1,091	937
Accrued unbilled revenue	766	761
Regulatory balancing accounts	1,124	936
Other	313	366
Regulatory assets	448	564
Inventories		
Gas stored underground and fuel oil	137	135
Materials and supplies	317	309
Income taxes receivable	563	186
Other	523	160
Total current assets	5,648	4,878
Property, Plant, and Equipment		
Electric	42,881	39,701
Gas	14,379	12,571
Construction work in progress	1,834	1,894
Total property, plant, and equipment	59,094	54,166
Accumulated depreciation	(17,843)	(16,643)
Net property, plant, and equipment	41,251	37,523
Other Noncurrent Assets		
Regulatory assets	4,913	6,809
Nuclear decommissioning trusts	2,342	2,161
Income taxes receivable	81	171
Other	814	381
Total other noncurrent assets	8,150	9,522
TOTAL ASSETS	\$ 55,049	\$ 51,923

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 914	\$ 372
Long-term debt, classified as current	539	400
Accounts payable		
Trade creditors	1,293	1,241
Disputed claims and customer refunds	154	157
Regulatory balancing accounts	1,008	634
Other	432	419
Interest payable	887	865
Other	1,382	1,806
Total current liabilities	6,609	5,894
Noncurrent Liabilities		
Long-term debt	12,717	12,167
Regulatory liabilities	5,660	5,088
Pension and other postretirement benefits	1,530	3,497
Asset retirement obligations	3,539	2,919
Deferred income taxes	8,042	6,939
Other	2,111	1,959
Total noncurrent liabilities	33,599	32,569
Commitments and Contingencies (Note 14)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, \$5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at December 31, 2013 and 2012	1,322	1,322
Additional paid-in capital	5,821	4,682
Reinvested earnings	7,427	7,291
Accumulated other comprehensive income (loss)	13	(93)
Total shareholders' equity	14,841	13,460
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 55,049	\$ 51,923

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2013	2012	2011
Cash Flows from Operating Activities			
Net income	\$ 866	\$ 811	\$ 845
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	2,077	2,272	2,215
Allowance for equity funds used during construction	(101)	(107)	(87)
Deferred income taxes and tax credits, net	1,103	684	582
PSEP disallowed capital expenditures	196	353	-
Other	299	236	289
Effect of changes in operating assets and liabilities:			
Accounts receivable	(152)	(40)	(227)
Inventories	(10)	(24)	(63)
Accounts payable	99	(26)	51
Income taxes receivable/payable	(377)	(50)	(192)
Other current assets and liabilities	(404)	272	36
Regulatory assets, liabilities, and balancing accounts, net	(202)	291	(100)
Other noncurrent assets and liabilities	22	256	414
Net cash provided by operating activities	3,416	4,928	3,763
Cash Flows from Investing Activities			
Capital expenditures	(5,207)	(4,624)	(4,038)
Decrease in restricted cash	29	50	200
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,619	1,133	1,928
Purchases of nuclear decommissioning trust investments	(1,604)	(1,189)	(1,963)
Other	21	16	14
Net cash used in investing activities	(5,142)	(4,614)	(3,859)
Cash Flows from Financing Activities			
Borrowings under revolving credit facilities	-	-	208
Repayments under revolving credit facilities	-	-	(208)
Net issuances (repayments) of commercial paper, net of discount of \$2, \$3, and \$4 at respective dates	542	(1,021)	782
Proceeds from issuance of short-term debt	-	-	250
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of \$18, \$13, and \$8 at respective dates	1,532	1,137	792
Short-term debt matured	-	(250)	(250)
Long-term debt matured or repurchased	(861)	(50)	(700)
Energy recovery bonds matured	-	(423)	(404)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(716)	(716)	(716)
Equity contribution	1,140	885	555
Other	(26)	28	54
Net cash provided by (used in) financing activities	1,597	(424)	349
Net change in cash and cash equivalents	(129)	(110)	253
Cash and cash equivalents at January 1	194	304	51
Cash and cash equivalents at December 31	\$ 65	\$ 194	\$ 304
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	\$ (600)	\$ (574)	\$ (627)
Income taxes, net	(62)	174	(50)
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	\$ 322	\$ 362	\$ 308
Terminated capital leases	-	136	-

See accompanying Notes to the Consolidated Financial Statements.

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

	Preferred Stock	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance at December 31, 2010	<u>\$ 258</u>	<u>\$ 1,322</u>	<u>\$ 3,241</u>	<u>\$ 7,095</u>	<u>\$ (195)</u>	<u>\$ 11,721</u>
Net income	-	-	-	845	-	845
Other comprehensive loss	-	-	-	-	(7)	(7)
Equity contribution	-	-	555	-	-	555
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2011	<u>258</u>	<u>1,322</u>	<u>3,796</u>	<u>7,210</u>	<u>(202)</u>	<u>12,384</u>
Net income	-	-	-	811	-	811
Other comprehensive income	-	-	-	-	109	109
Equity contribution	-	-	885	-	-	885
Tax benefit from employee stock plans	-	-	1	-	-	1
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2012	<u>258</u>	<u>1,322</u>	<u>4,682</u>	<u>7,291</u>	<u>(93)</u>	<u>13,460</u>
Net income	-	-	-	866	-	866
Other comprehensive income	-	-	-	-	106	106
Equity contribution	-	-	1,140	-	-	1,140
Tax expense from employee stock plans	-	-	(1)	-	-	(1)
Common stock dividend	-	-	-	(716)	-	(716)
Preferred stock dividend	-	-	-	(14)	-	(14)
Balance at December 31, 2013	<u>\$ 258</u>	<u>\$ 1,322</u>	<u>\$ 5,821</u>	<u>\$ 7,427</u>	<u>\$ 13</u>	<u>\$ 14,841</u>

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

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

This is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Consolidated Financial Statements. The Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation and the Utility operate in one segment.

The accompanying Consolidated Financial Statements have been prepared in accordance with GAAP and the instructions to Form 10-K and Regulation S-X promulgated by the SEC. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions, that are difficult to predict. Some of the more critical estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation and Regulated Operations

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

The Utility also records a regulatory balancing account asset or liability for differences between actual customer billings and authorized revenue requirements that are probable of recovery or refund. These differences do not have an impact on net income. The Utility also records differences between incurred costs and customer billings or authorized revenue meant to recover those costs. To the extent these differences are probable of recovery or refund, the Utility records a regulatory balancing account asset or liability, respectively, and the differences do not have an impact on net income. See "Revenue Recognition" below.

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

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable.

Cash and Cash Equivalents

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

Restricted Cash

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See Note 12 below.)

Allowance for Doubtful Accounts Receivable

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

Inventories

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

The Utility also purchases greenhouse gas emission allowances that are recorded as inventory. They are carried at weighted average cost and included in Other Noncurrent Assets – Other in the Consolidated Balance Sheets. The costs of the greenhouse gas emissions are expensed and recoverable through rates.

Property, Plant, and Equipment

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

(in millions, except estimated useful lives)	Estimated Useful Lives (years)	Balance at December 31,	
		2013	2012
Electricity generating facilities ⁽¹⁾	20 to 100	\$ 9,116	\$ 8,253
Electricity distribution facilities	10 to 55	25,333	23,767
Electricity transmission	10 to 70	8,429	7,681
Natural gas distribution facilities	20 to 53	9,117	8,257
Natural gas transportation and storage	5 to 65	5,265	4,314
Construction work in progress		1,834	1,894
Total property, plant, and equipment		59,094	54,166
Accumulated depreciation		(17,843)	(16,643)
Net property, plant, and equipment		\$ 41,251	\$ 37,523

(1) Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as it is used based on the amount of energy output. (See Note 14 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility’s composite depreciation rates were 3.51% in 2013, 3.63% in 2012, and 3.67% in 2011. The useful lives of the Utility’s property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of future removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC represents the estimated costs of debt (i.e., interest) and equity funds used to finance regulated plant additions and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recorded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of \$47 million and \$101 million during 2013, \$49 million and \$107 million during 2012, and \$40 million and \$87 million during 2011.

Asset Retirement Obligations

PG&E Corporation and the Utility record an ARO at discounted fair value in the period in which the obligation is incurred if the discounted fair value can be reasonably estimated. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the ARO is accreted to its present value. PG&E Corporation and the Utility also record an ARO if a legal obligation to perform an asset removal exists and can be reasonably estimated, but performance is conditional upon a future event. The Utility recognizes timing differences between the recognition of costs and the costs recovered through the ratemaking process as regulatory assets or liabilities. (See Note 3 below.) The Utility has an ARO primarily for its nuclear generation facilities, certain fossil fuel-fired generation facilities, and gas transmission system assets.

For the year ended December 31, 2013, the Utility recorded an increase of \$596 million to its ARO. The increase primarily reflects a higher expected cost per unit of transmission pipeline replacements.

Detailed studies of the cost to decommission the Utility’s nuclear generation facilities are conducted every three years in conjunction with the Nuclear Decommissioning Cost Triennial Proceeding conducted by the CPUC. In December 2012, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility’s nuclear power plants increased by \$1.4 billion in 2012 due to higher spent nuclear fuel disposal costs and an increase in the scope of work. A significant portion of the increase in decommissioning cost estimates is due to the need to develop on-site storage for spent nuclear fuel because the federal government has failed to meet its obligation to develop a permanent repository for the disposal of nuclear waste from nuclear facilities in the United States. The Utility expects that it will recover its future on-site storage costs from the federal government. Recovered amounts will be refunded to customers through rates.

The estimated undiscounted nuclear decommissioning cost for the Utility’s nuclear generation facilities was approximately \$3.5 billion at December 31, 2013 and 2012, as filed in the 2012 triennial proceeding. In future dollars, the estimated nuclear decommissioning cost is approximately \$6.1 billion at December 31, 2013 and 2012. These estimates are based on the 2012 decommissioning cost studies and are prepared in accordance with CPUC requirements. The estimated nuclear decommissioning cost in future dollars is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was \$2.5 billion at December 31,

2013 and 2012.

A reconciliation of the changes in the ARO liability is as follows:

(in millions)

ARO liability at December 31, 2011	\$	1,609
Revision in estimated cash flows		1,301
Accretion		101
Liabilities settled		(92)
ARO liability at December 31, 2012		<u>2,919</u>
Revision in estimated cash flows		596
Accretion		130
Liabilities settled		(107)
ARO liability at December 31, 2013	\$	<u><u>3,538</u></u>

The Utility has identified the following AROs for which a reasonable estimate of fair value could not be made. As a result, the Utility has not recorded a liability related to these AROs:

- *Restoration of land to its pre-use condition under the terms of certain land rights agreements.* Land rights will be maintained for the foreseeable future, and therefore, the Utility cannot reasonably estimate the settlement date(s) or range of settlement dates for the obligations associated with these assets;
- *Removal and proper disposal of lead-based paint contained in some Utility facilities.* The Utility does not have information available that specifies which facilities contain lead-based paint and, therefore, cannot reasonably estimate the settlement date(s) associated with the obligations; and
- *Removal of certain communications equipment from leased property, and retirement activities associated with substation and certain hydroelectric facilities.* The Utility will maintain and continue to operate its hydroelectric facilities until the operation of a facility becomes uneconomical. The operation of the majority of the Utility's hydroelectric facilities is currently, and for the foreseeable future, expected to be economically beneficial. Therefore, the settlement date(s) cannot be reasonably estimated at this time.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. During 2013 and 2012, the Utility recorded charges of \$196 million and \$353 million, respectively, for PSEP capital costs that are expected to exceed the CPUC's authorized levels or that are specifically disallowed. (See "Natural Gas Matters" in Note 14 below). No material disallowance losses were recorded in 2011.

Gains and Losses on Debt Extinguishments

Deferred gains and losses on debt extinguishments are recorded to current assets – regulatory assets and other noncurrent assets – regulatory assets in the Consolidated Balance Sheets. Gains and losses on debt extinguishments associated with regulated operations are deferred and amortized over a period consistent with the recovery of costs through regulated rates. PG&E Corporation and the Utility recorded unamortized loss on debt extinguishments, net of gain, of \$157 million, \$163 million, and \$186 million at December 31, 2013, 2012, and 2011, respectively. The amortization expense related to this loss was \$23 million in both 2013 and 2012, and \$18 million in 2011.

Revenue Recognition

The Utility recognizes revenues as electricity and natural gas services are delivered, and includes amounts for services rendered but not yet billed at the end of the period.

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

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

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

The Utility's revenues and net income can be affected by incentive ratemaking mechanisms that adjust rates depending on the extent to which the Utility meets certain performance criteria.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. The income tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expense. (See Note 8 below.)

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

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

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

Nuclear Decommissioning Trusts

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

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

Variable Interest Entities

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is known as the VIE's primary beneficiary and is required to consolidate the VIE. In determining whether consolidation of a particular entity is required, PG&E Corporation and the Utility first evaluate whether the entity is a VIE. If the entity is a VIE, PG&E Corporation and the Utility use a qualitative approach to determine if either is the primary beneficiary of the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at December 31, 2013, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial exposure is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2013, it did not consolidate any of them.

PG&E Corporation affiliates have entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of \$362 million from 2010 to 2013 to these companies in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. At December 31, 2013 and 2012, the carrying amount of PG&E Corporation's investment in these agreements was \$98 million and \$166 million, respectively. PG&E Corporation has no material remaining commitment to fund these agreements. PG&E Corporation determined that it does not have control over the companies' significant economic activities, such as the design of the companies, vendor selection, construction, and the ongoing operations of the companies. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at December 31, 2013, it did not consolidate any of them.

Other Accounting Policies

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Derivatives" in Note 9, "Fair Value Measurements" in Note 10, and "Contingencies" in Note 14 of the Notes to the Consolidated Financial Statements.

Adoption of New Accounting Pronouncements

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an ASU that requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013.

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income for the year ended December 31, 2013 consisted of the following:

(in millions)	Pension Benefits	Other Benefits	Other Investments	Total
Beginning balance	\$ (28)	\$ (77)	\$ 4	\$ (101)
Other comprehensive income before reclassifications:				
Unrecognized net actuarial loss (net of taxes of \$804, \$35, and \$0, respectively)	1,169	45	-	1,214
Transfer to regulatory account (net of taxes of \$790, \$22, and \$0, respectively)	(1,150)	31	-	(1,119)
Gain on investments (net of taxes of \$0, \$0, and \$26, respectively)	-	-	38	38
Amounts reclassified from other comprehensive income: ⁽¹⁾				
Amortization of prior service cost (net of taxes of \$8, \$10, and \$0, respectively)	12	13	-	25
Amortization of net actuarial loss (net of taxes of \$45, \$3, and \$0, respectively)	66	3	-	69
Transfer to regulatory account (net of taxes of \$54, \$0, and \$0, respectively)	(76)	-	-	(76)
Net current period other comprehensive income	21	92	38	151
Ending balance	\$ (7)	\$ 15	\$ 42	\$ 50

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

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

Disclosures about Offsetting Assets and Liabilities

In January 2013, the Financial Accounting Standards Board issued an ASU that clarifies the scope of disclosures about offsetting assets and liabilities. The guidance requires an entity to disclose gross and net information about derivatives that are offset in the balance sheet or subject to an enforceable master-netting arrangement or similar agreement. The ASU became effective for PG&E Corporation and the Utility on January 1, 2013. (See Note 9 below.)

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are composed of the following:

(in millions)	Balance at December 31,		Recovery Period
	2013	2012	
Pension benefits ⁽¹⁾	\$ 1,444	\$ 3,275	N/A ⁽⁴⁾
Deferred income taxes ⁽¹⁾	1,835	1,627	1 - 45 years
Utility retained generation ⁽²⁾	503	552	11 years
Environmental compliance costs ⁽¹⁾	628	604	32 years
Price risk management ⁽¹⁾	106	210	9 years
Electromechanical meters ⁽³⁾	135	194	4 years
Unamortized loss, net of gain, on reacquired debt ⁽¹⁾	135	141	13 years
Other	127	206	Various
Total long-term regulatory assets	\$ 4,913	\$ 6,809	

⁽¹⁾ Represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP and also includes amounts that otherwise would be recorded to accumulated other comprehensive loss in the Consolidated Balance Sheets. (See Note 11 below.)

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

⁽³⁾ Represents the expected future recovery of the net book value of electromechanical meters that were replaced with SmartMeter™ devices.

⁽⁴⁾ The Utility expects to continuously recover pension benefits.

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

Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

(in millions)	Balance at December 31,	
	2013	2012
Cost of removal obligations ⁽¹⁾	\$ 3,844	\$ 3,625
Recoveries in excess of AROs ⁽²⁾	748	620
Public purpose programs ⁽³⁾	587	590
Other	481	253
Total long-term regulatory liabilities	\$ 5,660	\$ 5,088

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

⁽²⁾ Represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the Utility's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments. (See Note 10 below.)

⁽³⁾ Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily related to energy efficiency programs.

Regulatory Balancing Accounts

The Utility's recovery of a significant portion of revenue requirements and costs is decoupled from the volume of sales. The Utility records (1) differences between the Utility's authorized revenue requirement and actual customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility does not expect to collect or refund over the next 12 months are included in other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets.

The Utility sells and delivers electricity and natural gas, which includes procuring and generating electricity. The Utility also administers public purpose programs, primarily related to customer energy efficiency programs. The balancing accounts associated with these items will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

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

(in millions)	Receivable Balance at December 31,	
	2013	2012
Electric distribution	\$ 102	\$ 219
Utility generation	57	117
Gas distribution	70	44
Energy procurement	410	193
Public purpose programs	56	48
Other	429	315
Total regulatory balancing accounts receivable	\$ 1,124	\$ 936

(in millions)	Payable Balance at December 31,	
	2013	2012
Energy procurement	\$ 298	\$ 116
Public purpose programs	171	131
Other	539	387
Total regulatory balancing accounts payable	\$ 1,008	\$ 634

NOTE 4: DEBT

Long-Term Debt

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

(in millions)	December 31,	
	2013	2012
PG&E Corporation		
Senior notes, 5.75%, due 2014	350	350
Less: current portion	(350)	-
Total senior notes	-	350
Total PG&E Corporation long-term debt	-	350
Utility		
Senior notes:		
6.25% due 2013	-	400
4.80% due 2014	539	1,000
5.625% due 2017	700	700
8.25% due 2018	800	800
3.50% due 2020	800	800
4.25% due 2021	300	300
3.25% due 2021	250	250
2.45% due 2022	400	400
3.25% due 2023	375	-
3.85% due 2023	300	-
6.05% due 2034	3,000	3,000
5.80% due 2037	950	950
6.35% due 2038	400	400
6.25% due 2039	550	550
5.40% due 2040	800	800
4.50% due 2041	250	250
4.45% due 2042	400	400
3.75% due 2042	350	350
4.60% due 2043	375	-
5.125% due 2043	500	-
Less: current portion	(539)	(400)
Unamortized discount, net of premium	(51)	(51)
Total senior notes, net of current portion	11,449	10,899
Pollution control bonds:		
Series 1996 C, E, F, 1997 B, variable rates ⁽¹⁾ , due 2026 ⁽²⁾	614	614
Series 2004 A-D, 4.75%, due 2023 ⁽³⁾	345	345
Series 2009 A-D, variable rates ⁽⁴⁾ , due 2016 and 2026 ⁽⁵⁾	309	309
Total pollution control bonds	1,268	1,268
Total Utility long-term debt, net of current portion	12,717	12,167
Total consolidated long-term debt, net of current portion	\$ 12,717	\$ 12,517

⁽¹⁾ At December 31, 2013, interest rates on these bonds and the related loans ranged from 0.01% to 0.04%.

⁽²⁾ Each series of these bonds is supported by a separate letter of credit. In April 2013, the letters of credit were extended to April 1, 2018. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

⁽³⁾ The Utility has obtained credit support from an insurance company for these bonds.

⁽⁴⁾ At December 31, 2013, interest rates on these bonds and the related loans ranged from 0.01% to 0.02%.

⁽⁵⁾ Each series of these bonds is supported by a separate direct-pay letter of credit. Series A and B letters of credit expire on May 31, 2016. In October 2013, Series C and D letters of credit were extended to December 3, 2016 to coincide with the maturity of the underlying bonds. Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant. In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geysers Power Company, LLC pursuant to purchase and sale agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance the Geysers project are outstanding. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control facilities.

Repayment Schedule

PG&E Corporation's and the Utility's combined short-term and long-term debt principal repayment amounts at December 31, 2013 are reflected in the table below:

(in millions, except interest rates)	2014	2015	2016	2017	2018	Thereafter	Total
PG&E Corporation							
Average fixed interest rate	5.75%	-	-	-	-	-	5.75%
Fixed rate obligations	\$ 350	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 350
Utility							
Average fixed interest rate	4.80%	-	-	5.63%	8.25%	5.06%	5.29%
Fixed rate obligations	\$ 539	\$ -	\$ -	\$ 700	\$ 800	\$ 10,345	\$ 12,384
Variable interest rate as of December 31, 2013	-	-	0.02%	-	0.02%	-	0.02%
Variable rate obligations	\$ -	\$ -	\$ 309	\$ -	\$ 614	\$ -	\$ 923
Total consolidated debt	\$ 889	\$ -	\$ 309	\$ 700	\$ 1,414	\$ 10,345	\$ 13,657

(1) These bonds, due in 2016 and 2026, are backed by separate letters of credit that expire on May 31, 2016, December 3, 2016, or April 1, 2018.

Short-term Borrowings

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and the Utility's commercial paper program at December 31, 2013:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
PG&E Corporation	April 2018	\$ 300 ⁽¹⁾	\$ -	\$ 260	\$ -	\$ 40
Utility	April 2018	3,000 ⁽²⁾	79	-	914 ⁽³⁾	2,007 ⁽³⁾
Total revolving credit facilities		\$ 3,300	\$ 79	\$ 260	\$ 914	\$ 2,047

⁽¹⁾ Includes a \$100 million sublimit for letters of credit and a \$100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

⁽²⁾ Includes a \$1.0 billion sublimit for letters of credit and a \$300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

⁽³⁾ The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

For 2013, the average outstanding borrowings on PG&E Corporation's revolving credit facility was \$214 million and the maximum outstanding balance during the year was \$260 million. For 2013, the Utility's average outstanding commercial paper balance was \$542 million and the maximum outstanding balance during the year was \$1.1 billion. The Utility did not borrow under its credit facility in 2013.

Revolving Credit Facilities

In April 2013, PG&E Corporation and the Utility amended and restated their revolving credit facilities to extend their termination dates from May 31, 2016 to April 1, 2018. These agreements contain substantially similar terms as their original 2011 credit agreements. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other corporate purposes. At PG&E Corporation's and the Utility's request and at the sole discretion of each lender, the facilities may be extended for additional periods. Provided certain conditions are met, PG&E Corporation and the Utility have the right to increase, in one or more requests, given not more frequently than once a year, the aggregate lenders' commitments under the revolving credit facilities by up to \$100 million and \$500 million, respectively, in the aggregate for all such increases.

Borrowings under the revolving credit facilities (other than swingline loans) bear interest based, at PG&E Corporation's and the Utility's election, on (1) a London Interbank Offered Rate plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent's announced base rate, 0.5% above the federal funds rate, or the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. PG&E Corporation and the Utility also will pay a facility fee on the total commitments of the lenders under the revolving credit facilities. The applicable margins and the facility fees will be based on PG&E Corporation's and the Utility's senior unsecured debt ratings issued by Standard & Poor's Rating Services and Moody's Investor Service. Facility fees are payable quarterly in arrears.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary provisions for revolving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the 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.

Commercial Paper Programs

At December 31, 2013, the average yield on outstanding Utility commercial paper was 0.26%.

In January 2014, PG&E Corporation established a commercial paper program. PG&E Corporation will treat the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility.

The borrowings from PG&E Corporation and the Utility's commercial paper programs are used primarily to fund temporary financing needs. Liquidity support for these borrowings is provided by available capacity under their respective revolving credit facilities, as described above. The commercial paper may have maturities up to 365 days and ranks equally with PG&E Corporation's and the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

NOTE 5 : COMMON STOCK AND SHARE-BASED COMPENSATION

PG&E Corporation had 456,670,424 shares of common stock outstanding at December 31, 2013. PG&E Corporation held all of the Utility's outstanding common stock at December 31, 2013.

In May 2013, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to \$400 million. As of December 31, 2013, PG&E Corporation had old common stock having an aggregate gross sales price of \$395 million and had the ability to issue an additional \$5 million of its common stock under this agreement. During 2013, PG&E Corporation paid commissions of \$3 million under this agreement.

During 2013, PG&E Corporation issued 26 million shares of its common stock for aggregate net cash proceeds of \$1,045 million in the following transactions:

- 7 million shares were sold in an underwritten public offering for cash proceeds of \$300 million, net of fees and commissions;
- 8 million shares were issued for cash proceeds of \$290 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and
- 11 million shares were sold for cash proceeds of \$455 million, net of commissions paid of \$4 million, under equity distribution agreements.

Dividends

The Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. For 2013, the Board of Directors of PG&E Corporation declared a quarterly common stock dividend of \$0.455 per share.

Under their respective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio, \$493 million of the Utility's reinvested earnings was restricted at December 31, 2013. In addition, the CPUC requires the Utility to maintain a capital structure composed of at least 52% equity on average. At December 31, 2013, the Utility was required to maintain reinvested earnings of \$7.4 billion as equity to meet this requirement.

In addition, to comply with the revolving credit facility's 65% ratio requirement and the CPUC's requirement to maintain a 52% equity component, \$7.7 billion and \$14.6 billion of the Utility's net assets were restricted at December 31, 2013 to comply with these requirements, respectively, and could not be transferred to PG&E Corporation in the form of cash dividends. As a holding company, PG&E Corporation depends on cash distributions from the Utility to meet its debt service and other financial obligations and to pay dividends on its common stock.

Long-Term Incentive Plan

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including stock options, stock appreciation rights, restricted stock awards, RSUs, performance shares, deferred compensation awards, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) has been reserved for issuance under the 2006 LTIP, of which 3,310,474 shares were available for future awards at December 31, 2013.

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2013, 2012, and 2011:

(in millions)	2013	2012	2011
Restricted stock units	\$ 36	\$ 31	\$ 23
Performance shares:			
Equity awards	28	26	16
Liability awards	-	-	(13)
Total compensation expense (pre-tax)	\$ 64	\$ 57	\$ 26
Total compensation expense (after-tax)	\$ 38	\$ 34	\$ 16

Share-based compensation costs capitalized during 2013, 2012, and 2011 was immaterial. There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Restricted Stock Units

RSU awards issued and outstanding under the LTIP generally vest over three year periods. RSUs generally vest in 20% increments on the first business day of March in year one, two, and three, with the remaining 40% vesting on the first business day of March in year four. Vested RSUs are settled in shares of PG&E Corporation common stock. Additionally, upon settlement, RSU recipients receive payment for the amount of dividend equivalents associated with the vested RSUs that have accrued since the date of grant. RSU expense is generally recognized ratably over the vesting period based on the fair values determined. The weighted average grant-date fair value for RSUs granted during 2013, 2012, and 2011 was \$42.92, \$42.17, and \$45.10, respectively. The total fair value of RSUs that vested during 2013, 2012, and 2011 was \$30 million, \$18 million, and \$11 million, respectively. The tax benefit from RSUs that vested during each period was not material. As of December 31, 2013, \$50 million of total unrecognized compensation costs related to nonvested RSUs was expected to be recognized over the remaining weighted average period of 2.17 years.

The following table summarizes RSU activity for 2013:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1	2,069,291	\$ 42.52
Granted	993,115	\$ 42.92
Vested	(719,071)	\$ 41.03
Forfeited	(43,314)	\$ 42.68
Nonvested at December 31	<u>2,300,021</u>	\$ 43.16

Performance Shares

Performance shares awarded to recipients under the LTIP are for a specified number of shares of common stock (or cash with respect to grants before 2010) based on PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period. Performance shares vest after three years of service. Performance share expense is generally recognized ratably over the applicable three-year period based on the fair values determined. Dividend equivalents on performance shares, if any, will be paid in cash upon the vesting date based on the amount of common stock to which the recipients are entitled.

Total compensation expense for performance shares is based on the grant-date fair value, which is determined using a Monte Carlo simulation valuation model. The weighted average grant-date fair value for performance shares granted during 2013, 2012, and 2011 was \$33.45, \$41.93, and \$33.91 respectively. There was no tax benefit associated with performance shares that vested during each of these periods. As of December 31, 2013, \$29 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted average period of 1.25 years.

The following table summarizes performance shares classified as equity awards activity for 2013:

	Number of Performance Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,497,473	\$ 38.15
Granted	911,620	\$ 33.45
Vested	-	\$ -
Forfeited ⁽¹⁾	(617,773)	\$ 34.22
Nonvested at December 31	<u>1,791,320</u>	\$ 37.85

⁽¹⁾ Includes performance shares that expired with zero value as performance targets were not met.

NOTE 6 : PREFERRED STOCK

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

The Utility has authorized 75 million shares of \$25 par value preferred stock and 10 million shares of \$100 par value preferred stock. The Utility specifies that 5,784,825 shares of the \$25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. The following table summarizes the Utility's outstanding preferred stock, none of which had mandatory redemption provisions at December 31, 2013 and 2012:

(in millions, except share amounts, redemption

price, and par value)	Shares Outstanding	Redemption Price	Balance
Nonredeemable \$25 par value preferred stock			
5.00% Series	400,000	N/A	\$ 10
5.50% Series	1,173,163	N/A	30
6.00% Series	4,211,662	N/A	105
Total nonredeemable preferred stock	5,784,825		\$ 145
Redeemable \$25 par value preferred stock			
4.36% Series	418,291	\$ 25.75	\$ 11
4.50% Series	611,142	26.00	15
4.80% Series	793,031	27.25	20
5.00% Series	1,778,172	26.75	44
5.00% Series A	934,322	26.75	23
Total redeemable preferred stock	4,534,958		\$ 113
Preferred stock			\$ 258

At December 31, 2013, annual dividends on the Utility's nonredeemable preferred stock ranged from \$1.25 to \$1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2013, annual dividends on redeemable preferred stock ranged from \$1.09 to \$1.25 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. During each of 2013, 2012, and 2011 the Utility paid \$14 million of dividends on preferred stock.

NOTE 7: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-based compensation in the calculation of diluted EPS. The following is a reconciliation of PG&E Corporation's income available for common shareholders and weighted average common shares outstanding for calculating diluted EPS for 2013, 2012 and 2011.

(in millions, except per share amounts)	Year Ended December 31,		
	2013	2012	2011
Income available for common shareholders	\$ 814	\$ 816	\$ 844
Weighted average common shares outstanding, basic	444	424	401
Add incremental shares from assumed conversions:			
Employee share-based compensation	1	1	1
Weighted average common share outstanding, diluted	445	425	402
Total earnings per common share, diluted	<u>\$ 1.83</u>	<u>\$ 1.92</u>	<u>\$ 2.10</u>

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

NOTE 8 : INCOME TAXES

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

(in millions)	PG&E Corporation			Utility		
	Year Ended December 31,					
	2013	2012	2011	2013	2012	2011
Current:						
Federal	\$ (218)	\$ (74)	\$ (77)	\$ (222)	\$ (52)	\$ (83)
State	(26)	33	152	(23)	41	161
Deferred:						
Federal	552	374	504	604	404	534
State	(35)	(92)	(135)	(28)	(91)	(128)
Tax credits	(5)	(4)	(4)	(5)	(4)	(4)
Income tax provision	<u>\$ 268</u>	<u>\$ 237</u>	<u>\$ 440</u>	<u>\$ 326</u>	<u>\$ 298</u>	<u>\$ 480</u>

The following table describes net deferred income tax liabilities:

(in millions)	PG&E Corporation		Utility	
	Year Ended December 31,			
	2013	2012	2013	2012
Deferred income tax assets:				
Customer advances for construction	\$ 90	\$ 101	\$ 90	\$ 101
Reserve for damages	161	175	161	175
Environmental reserve	152	97	152	97
Compensation	167	229	102	179
Net operating loss carryforward	890	938	670	736
GHG allowances	108	34	108	34
Other	135	230	128	221
Total deferred income tax assets	<u>\$ 1,703</u>	<u>\$ 1,804</u>	<u>\$ 1,411</u>	<u>\$ 1,543</u>
Deferred income tax liabilities:				
Regulatory balancing accounts	\$ 261	\$ 256	\$ 261	\$ 256
Property related basis differences	8,048	7,449	8,038	7,447
Income tax regulatory asset	748	663	748	663
Other	151	173	86	99
Total deferred income tax liabilities	<u>\$ 9,208</u>	<u>\$ 8,541</u>	<u>\$ 9,133</u>	<u>\$ 8,465</u>
Total net deferred income tax liabilities	<u>\$ 7,505</u>	<u>\$ 6,737</u>	<u>\$ 7,722</u>	<u>\$ 6,922</u>
Classification of net deferred income tax liabilities:				
Included in current liabilities (assets)	\$ (318)	\$ (11)	\$ (320)	\$ (17)
Included in noncurrent liabilities	7,823	6,748	8,042	6,939
Total net deferred income tax liabilities	<u>\$ 7,505</u>	<u>\$ 6,737</u>	<u>\$ 7,722</u>	<u>\$ 6,922</u>

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

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2013	2012	2011	2013	2012	2011
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	(3.1)	(3.9)	1.1	(2.2)	(3.0)	1.6
Effect of regulatory treatment of fixed asset differences	(4.2)	(4.1)	(4.4)	(3.8)	(3.9)	(4.2)
Tax credits	(0.4)	(0.6)	(0.5)	(0.4)	(0.6)	(0.5)
Benefit of loss carryback	(1.1)	(0.7)	(1.9)	(1.0)	(0.4)	(2.1)
Non deductible penalties	0.8	0.6	6.5	0.7	0.5	6.3
Other, net	(2.2)	(3.8)	(1.5)	(0.9)	(0.8)	0.1
Effective tax rate	24.8%	22.5%	34.3%	27.4%	26.8%	36.2%

Unrecognized tax benefits

The following table reconciles the changes in unrecognized tax benefits:

	PG&E Corporation			Utility		
	2013	2012	2011	2013	2012	2011
(in millions)						
Balance at beginning of year	\$ 581	\$ 506	\$ 714	\$ 575	\$ 503	\$ 712
Additions for tax position taken during a prior year	12	32	2	12	26	2
Reductions for tax position taken during a prior year	(6)	(13)	(198)	(6)	(10)	(196)
Additions for tax position taken during the current year	79	67	3	79	67	-
Settlements	-	(11)	(15)	-	(11)	(15)
Balance at end of year	\$ 666	\$ 581	\$ 506	\$ 660	\$ 575	\$ 503

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2013 for PG&E Corporation and the Utility was \$29 million, with the remaining balance representing the potential deferral of taxes to later years.

Tax settlements and years that remain subject to examination

PG&E Corporation participates in the Compliance Assurance Process, a real-time IRS audit intended to expedite resolution of tax matters. The Compliance Assurance Process audit culminates with a letter from the IRS indicating its acceptance of the return.

In January 2014, PG&E Corporation received the IRS closing agreements for the 2008 and 2010 audit years, subject to the approval by the Joint Committee on Taxation of the U.S. Congress. The IRS has previously accepted the 2009 tax return without adjustments. The IRS is currently reviewing several matters pertaining to the 2011 and 2012 tax returns. The most significant of these matters relates to the repairs accounting method changes.

The IRS has been working with the utility industry to provide guidance concerning the deductibility of repairs. PG&E Corporation and the Utility expect the IRS to issue guidance with respect to repairs made in the natural gas transmission and distribution businesses during 2014. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the guidance to be issued by the IRS and the resolution of the IRS audits related to the 2010, 2011, and 2012 tax returns. As of December 31, 2013, PG&E Corporation and the Utility believe that it is reasonably possible that unrecognized tax benefits will decrease by approximately \$350 million within the next 12 months.

Carryforwards

As of December 31, 2013, PG&E Corporation had approximately \$3.3 billion of federal net operating loss carryforwards and \$68 million of tax credit carryforwards, which will expire between 2029 and 2033. In addition, PG&E Corporation had approximately \$121 million of loss carryforwards related to charitable contributions, which will expire between 2014 and 2018. PG&E Corporation believes it is more likely than not the tax benefits associated with the federal operating loss, charitable contributions, and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2013. As of December 31, 2013, PG&E Corporation had approximately \$15 million of federal net operating loss carryforwards related to the tax benefit on employee stock plans that would be recorded in additional paid-in capital when used.

NOTE 9 : DERIVATIVES

Use of Derivative Instruments

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including forward contracts, swap agreements, futures contracts, and option contracts.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. As long as the current ratemaking mechanism discussed above remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives, the Utility expects to recover fully, in rates, all costs related to derivatives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

PG&E Corporation and the Utility offset cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset and the intention to offset exist.

The Utility elects the normal purchase and sale exception for eligible derivatives. Derivatives that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of derivatives that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets at fair value, but are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

Electricity Procurement

The Utility enters into third-party power purchase agreements for electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivatives. The Utility elects the normal purchase and sale exception for eligible derivatives.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce volatility in customer rates, the Utility may enter into financial instruments, such as futures, options, or swaps, to effectively fix and/or cap the price of future purchases and reduce cash flow variability associated with fluctuating electricity prices. These financial contracts are considered derivatives.

Electric Transmission Congestion Revenue Rights

The California electric transmission grid, controlled by the CAISO, is subject to transmission constraints when there is insufficient transmission capacity to supply the market. The CAISO imposes congestion charges on market participants to manage transmission congestion. The revenue generated from congestion charges is allocated to holders of CRRs. CRRs allow market participants to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities, such as the Utility, are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). The Utility can participate in the allocation and auction phases of the annual and monthly CRR processes. CRRs are considered derivatives.

Natural Gas Procurement (Electric Fuels Portfolio)

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through physical natural gas commodity purchases to fuel natural gas generating facilities, and electricity procurement contracts indexed to natural gas prices. To reduce the volatility in customer rates, the Utility may enter into financial instruments, such as futures, options, or swaps. The Utility also enters into fixed-price forward contracts for natural gas to reduce future cash flow variability from fluctuating natural gas prices. These instruments are considered derivatives.

Natural Gas Procurement (Core Gas Supply Portfolio)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as “core” customers. The Utility does not procure natural gas for industrial and large commercial, or “non-core,” customers. Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of natural gas may be purchased or sold in the multi-month, monthly, and to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments, such as futures, swaps and options, as part of its core winter hedging program in order to manage customer exposure to high natural gas prices during peak winter months. These financial instruments are considered derivatives.

Volume of Derivative Activity

At December 31, 2013, the volumes of PG&E Corporation’s and the Utility’s outstanding derivatives were as follows:

Underlying Product	Instruments	Contract Volume ⁽¹⁾			
		Less Than 1 Year	1 Year or Greater but Less Than 3 Years	3 Years or Greater but Less Than 5 Years	5 Years or Greater ⁽²⁾
Natural Gas ⁽³⁾ (MMBtus ⁽⁴⁾)	Forwards and Swaps	243,213,288	79,735,000	8,892,500	-
	Options	169,123,208	87,689,708	3,450,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	2,537,023	2,009,505	2,008,046	1,534,695
	Congestion Revenue Rights	73,510,440	83,747,782	63,718,517	29,945,852

⁽¹⁾ Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.

⁽²⁾ Derivatives in this category expire between 2019 and 2022.

⁽³⁾ Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

⁽⁴⁾ Million British Thermal Units.

At December 31, 2012, the volumes of PG&E Corporation's and the Utility's outstanding derivatives were as follows:

Underlying Product	Instruments	Contract Volume ⁽¹⁾			
		Less Than 1 Year	1 Year or Greater but Less Than 3 Years	3 Years or Greater but Less Than 5 Years	5 Years or Greater ⁽²⁾
Natural Gas ⁽³⁾ (MMBtus ⁽⁴⁾)	Forwards and Swaps	329,466,510	98,628,398	5,490,000	-
	Options	221,587,431	216,279,767	10,050,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	2,537,023	3,541,046	2,009,505	2,538,718
	Options	-	239,015	239,233	119,508
	Congestion				
	Revenue Rights	74,198,690	74,187,803	74,240,147	25,699,804

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.

(2) Derivatives in this category expire between 2018 and 2023.

(3) Amounts shown are for the combined positions of the electric fuels and core gas supply portfolios.

(4) Million British Thermal Units .

Presentation of Derivative Instruments in the Financial Statements

In PG&E Corporation's and the Utility's Consolidated Balance Sheets, derivatives are presented on a net basis by counterparty where the right and the intention to offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At December 31, 2013, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk			
	Gross Derivative	Netting	Cash Collateral	Total Derivative
	Balance		Balance	Balance
Current assets – other	\$ 42	\$ (10)	\$ 16	\$ 48
Other noncurrent assets – other	99	(4)	-	95
Current liabilities – other	(122)	10	69	(43)
Noncurrent liabilities – other	(110)	4	2	(104)
Total commodity risk	\$ (91)	\$ -	\$ 87	\$ (4)

At December 31, 2012, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk			
	Gross Derivative	Netting	Cash Collateral	Total Derivative
	Balance		Balance	Balance
Current assets – other	\$ 48	\$ (25)	\$ 36	\$ 59
Other noncurrent assets – other	99	(11)	-	88
Current liabilities – other	(255)	25	115	(115)
Noncurrent liabilities – other	(221)	11	14	(196)
Total commodity risk	\$ (329)	\$ -	\$ 165	\$ (164)

Gains and losses recorded on PG&E Corporation's and the Utility's derivatives were as follows:

(in millions)	Commodity Risk		
	For the year ended December 31,		
	2013	2012	2011
Unrealized gain/(loss) - regulatory assets and liabilities ⁽¹⁾	\$ 238	\$ 391	\$ 21
Realized loss - cost of electricity ⁽²⁾	(178)	(486)	(558)
Realized loss - cost of natural gas ⁽²⁾	(22)	(38)	(106)
Total commodity risk	\$ 38	\$ (133)	\$ (643)

⁽¹⁾ Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

⁽²⁾ These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with derivatives are included in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At December 31, 2013, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

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

(in millions)	Balance at December 31,	
	2013	2012
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	\$ (79)	\$ (266)
Related derivatives in an asset position	4	59
Collateral posting in the normal course of business related to these derivatives	65	103
Net position of derivative contracts/additional collateral posting requirements ⁽¹⁾	\$ (10)	\$ (104)

⁽¹⁾ This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

NOTE 10 : FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1** – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2** – Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3** – Unobservable inputs which are supported by little or no market activities.

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

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (assets held in rabbi trusts and other investments are held by PG&E Corporation and not the Utility):

(in millions)	Fair Value Measurements				
	At December 31, 2013				
	Level 1	Level 2	Level 3	Netting ⁽¹⁾	Total
Assets:					
Money market investments	\$ 226	\$ -	\$ -	\$ -	\$ 226
Nuclear decommissioning trusts					
Money market investments	38	-	-	-	38
U.S. equity securities	1,046	11	-	-	1,057
Non-U.S. equity securities	457	-	-	-	457
U.S. government and agency securities	760	156	-	-	916
Municipal securities	-	25	-	-	25
Other fixed-income securities	-	162	-	-	162
Total nuclear decommissioning trusts ⁽²⁾	2,301	354	-	-	2,655
Price risk management instruments					
(Note 9)					
Electricity	2	27	107	3	139
Gas	-	5	-	(1)	4
Total price risk management instruments	2	32	107	2	143
Rabbi trusts					
Fixed-income securities	-	39	-	-	39
Life insurance contracts	-	70	-	-	70
Total rabbi trusts	-	109	-	-	109
Long-term disability trust					
Money market investments	9	-	-	-	9
U.S. equity securities	-	14	-	-	14
Non-U.S. equity securities	-	12	-	-	12
Fixed-income securities	-	122	-	-	122
Total long-term disability trust	9	148	-	-	157
Other investments	84	-	-	-	84
Total assets	\$ 2,622	\$ 643	\$ 107	\$ 2	\$ 3,374
Liabilities:					
Price risk management instruments					
(Note 9)					
Electricity	\$ 19	\$ 72	\$ 137	\$ (84)	\$ 144
Gas	1	3	-	(1)	3
Total liabilities	\$ 20	\$ 75	\$ 137	\$ (85)	\$ 147

⁽¹⁾ Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

⁽²⁾ Represents amount before deducting \$313 million, primarily related to deferred taxes on appreciation of investment value.

(in millions)	Fair Value Measurements				
	At December 31, 2012				
	Level 1	Level 2	Level 3	Netting ⁽¹⁾	Total
Assets:					
Money market investments	\$ 209	\$ -	\$ -	\$ -	\$ 209
Nuclear decommissioning trusts					
Money market investments	21	-	-	-	21
U.S. equity securities	940	9	-	-	949
Non-U.S. equity securities	379	-	-	-	379
U.S. government and agency securities	681	139	-	-	820
Municipal securities	-	59	-	-	59
Other fixed-income securities	-	173	-	-	173
Total nuclear decommissioning trusts ⁽²⁾	<u>2,021</u>	<u>380</u>	<u>-</u>	<u>-</u>	<u>2,401</u>
Price risk management instruments					
(Note 9)					
Electricity	1	60	80	6	147
Gas	-	5	1	(6)	-
Total price risk management instruments	<u>1</u>	<u>65</u>	<u>81</u>	<u>-</u>	<u>147</u>
Rabbi trusts					
Fixed-income securities	-	30	-	-	30
Life insurance contracts	-	72	-	-	72
Total rabbi trusts	<u>-</u>	<u>102</u>	<u>-</u>	<u>-</u>	<u>102</u>
Long-term disability trust					
Money market investments	10	-	-	-	10
U.S. equity securities	-	14	-	-	14
Non-U.S. equity securities	-	11	-	-	11
Fixed-income securities	-	136	-	-	136
Total long-term disability trust	<u>10</u>	<u>161</u>	<u>-</u>	<u>-</u>	<u>171</u>
Total assets	<u>\$ 2,241</u>	<u>\$ 708</u>	<u>\$ 81</u>	<u>\$ -</u>	<u>\$ 3,030</u>
Liabilities:					
Price risk management instruments					
(Note 9)					
Electricity	\$ 155	\$ 144	\$ 160	\$ (156)	\$ 303
Gas	8	9	-	(9)	8
Total liabilities	<u>\$ 163</u>	<u>\$ 153</u>	<u>\$ 160</u>	<u>\$ (165)</u>	<u>\$ 311</u>

⁽¹⁾ Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

⁽²⁾ Represents amount before deducting \$240 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

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

Money Market Investments

PG&E Corporation and the Utility invest in money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as U.S. Treasury bills, U.S. agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's and the Utility's investments in these money market funds are valued using unadjusted prices for identical assets in an active market and are thus classified as Level 1. Money market funds are recorded as cash and cash equivalents in the Consolidated Balance Sheets.

Trust Assets

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock, which are valued based on unadjusted prices for identical securities in active markets and are classified as Level 1. Equity securities also include commingled funds, that are valued using a net asset value per share and are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world and are classified as Level 2. Price quotes for the assets held by these funds are readily observable and available.

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

Price Risk Management Instruments

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

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2. Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are valued based on prices observed in the CAISO auction, which are discounted at the risk-free rate. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions. CRRs are classified as Level 3.

Other Investments

Other investments in common stock are valued based on unadjusted prices for the investments and are actively traded on public exchanges. These investments are therefore considered Level 1 assets.

Transfers between Levels

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. For the years ended December 31, 2013 and 2012, there were no significant transfers between levels.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to the Chief Risk Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments. These models use pricing inputs from brokers and historical data. The market and credit risk management function and the Utility's finance function collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

CRRs and power purchase agreements are valued using historical prices or significant unobservable inputs derived from internally developed models. Historical prices include CRR auction prices. Unobservable inputs include forward electricity prices. Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

(in millions) Fair Value Measurement	Fair Value at December 31, 2013		Valuation Technique	Unobservable Input	Range ⁽¹⁾
	Assets	Liabilities			
Congestion revenue rights	\$ 107	\$ 32	Market approach	CRR auction prices	(6.47) - \$12.04
Power purchase agreements	\$ -	\$ 105	Discounted cash flow	Forward prices	\$23.43 - 51.75

⁽¹⁾ Represents price per megawatt-hour

(in millions) Fair Value Measurement	Fair Value at December 31, 2012		Valuation Technique	Unobservable Input	Range ⁽¹⁾
	Assets	Liabilities			
Congestion revenue rights	\$ 80	\$ 16	Market approach	CRR auction prices	(9.04) - \$55.15
Power purchase agreements	\$ -	\$ 145	Discounted cash flow	Forward prices	\$8.59 - 62.90

⁽¹⁾ Represents price per megawatt-hour

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the years ended December 31, 2013 and 2012, respectively:

(in millions)	Price Risk Management Instruments	
	2013	2012
Liability balance as of January 1	\$ (79)	\$ (74)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts ⁽¹⁾	49	(5)
Liability balance as of December 31	\$ (30)	\$ (79)

⁽¹⁾The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at December 31, 2013 and 2012, as they are short-term in nature or have interest rates that reset daily.
- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at December 31, 2013 and 2012.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

(in millions)	At December 31,			
	2013		2012	
	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
Debt (Note 4)				
PG&E Corporation	\$ 350	\$ 354	\$ 349	\$ 371
Utility	12,334	13,444	11,645	13,946

Available for Sale Investments

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

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of December 31, 2013				
Nuclear decommissioning trusts				
Money market investments	\$ 38	\$ -	\$ -	\$ 38
Equity securities				
U.S.	246	811	-	1,057
Non-U.S.	215	242	-	457
Debt securities				
U.S. government and agency securities	870	51	(5)	916
Municipal securities	24	2	(1)	25
Other fixed-income securities	163	1	(2)	162
Total nuclear decommissioning trusts ⁽¹⁾	1,556	1,107	(8)	2,655
Other investments	13	71	-	84
Total	\$ 1,569	\$ 1,178	\$ (8)	\$ 2,739
As of December 31, 2012				
Nuclear decommissioning trusts				
Money market investments	\$ 21	\$ -	\$ -	\$ 21
Equity securities				
U.S.	331	618	-	949
Non-U.S.	199	181	(1)	379
Debt securities				
U.S. government and agency securities	723	97	-	820
Municipal securities	56	4	(1)	59
Other fixed-income securities	168	5	-	173
Total ⁽¹⁾	\$ 1,498	\$ 905	\$ (2)	\$ 2,401

⁽¹⁾ Represents amounts before deducting \$313 million and \$240 million at December 31, 2013 and 2012, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

(in millions)	As of December 31, 2013
Less than 1 year	\$ 22
1–5 years	519
5–10 years	230
More than 10 years	332
Total maturities of debt securities	\$ 1,103

The following table provides a summary of activity for the debt and equity securities:

(in millions)	2013	2012	2011
Proceeds from sales and maturities of nuclear decommissioning trust investments	\$ 1,619	\$ 1,133	\$ 1,928
Gross realized gains on sales of securities held as available-for-sale	94	19	43
Gross realized losses on sales of securities held as available-for-sale	(13)	(17)	(30)

NOTE 11 : EMPLOYEE BENEFIT PLANS

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees, as well as contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Additionally, eligible employees hired after December 31, 2012 participate in the cash balance plan that was added to the defined benefit pension plan in 2012. Eligible employees hired before December 31, 2012 were given a one-time election to participate in the cash balance plan prospectively, or to continue participating in the existing defined benefit plan. The trusts underlying certain of these plans are qualified trusts under the Internal Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility's minimum funding requirements related to its pension plans was zero.

Change in Plan Assets, Benefit Obligations, and Funded Status

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2013 and 2012:

Pension Benefits

(in millions)	2013	2012
Change in plan assets:		
Fair value of plan assets at January 1	\$ 12,141	\$ 10,993
Actual return on plan assets	673	1,488
Company contributions	323	282
Benefits and expenses paid	(610)	(622)
Fair value of plan assets at December 31	\$ 12,527	\$ 12,141
Change in benefit obligation:		
Projected benefit obligation at January 1	\$ 15,541	\$ 14,000
Service cost for benefits earned	468	396
Interest cost	627	658
Actuarial (gain) loss	(1,950)	1,099
Plan amendments	-	9
Transitional costs	1	1
Benefits and expenses paid	(610)	(622)
Projected benefit obligation at December 31 ⁽¹⁾	\$ 14,077	\$ 15,541
Funded status:		
Current liability	\$ (6)	\$ (6)
Noncurrent liability	(1,544)	(3,394)
Accrued benefit cost at December 31	\$ (1,550)	\$ (3,400)

(1) PG&E Corporation's accumulated benefit obligation was \$12,659 million and \$13,778 million at December 31, 2013 and 2012, respectively.

Other Benefits

(in millions)

	2013	2012
Change in plan assets:		
Fair value of plan assets at January 1	\$ 1,758	\$ 1,491
Actual return on plan assets	64	191
Company contributions	145	149
Plan participant contribution	64	55
Benefits and expenses paid	(139)	(128)
Fair value of plan assets at December 31	\$ 1,892	\$ 1,758
Change in benefit obligation:		
Benefit obligation at January 1	\$ 1,940	\$ 1,885
Service cost for benefits earned	53	49
Interest cost	74	83
Actuarial gain	(415)	(23)
Plan amendments	-	5
Benefits paid	(123)	(119)
Federal subsidy on benefits paid	4	5
Plan participant contributions	64	55
Benefit obligation at December 31	\$ 1,597	\$ 1,940
Funded status ⁽¹⁾:		
Noncurrent asset	\$ 352	\$ -
Noncurrent liability	(57)	(181)
Accrued benefit cost at December 31	\$ 295	\$ (181)

⁽¹⁾ At December 31, 2013, the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position. At December 31, 2012, both the postretirement medical plan and the postretirement life insurance plan were in underfunded positions.

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

Components of Net Periodic Benefit Cost

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

Pension Benefits

(in millions)	2013	2012	2011
Service cost for benefits earned	\$ 468	\$ 396	\$ 320
Interest cost	627	658	660
Expected return on plan assets	(650)	(598)	(669)
Amortization of prior service cost	20	20	34
Amortization of net actuarial loss	111	123	50
Net periodic benefit cost	576	599	395
Less: transfer to regulatory account ⁽¹⁾	(238)	(301)	(139)
Total	\$ 338	\$ 298	\$ 256

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

Other Benefits

(in millions)	2013	2012	2011
Service cost for benefits earned	\$ 53	\$ 49	\$ 42
Interest cost	74	83	91
Expected return on plan assets	(79)	(77)	(82)
Amortization of transition obligation	-	24	26
Amortization of prior service cost	23	25	27
Amortization of net actuarial loss	6	6	4
Net periodic benefit cost	\$ 77	\$ 110	\$ 108

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

Components of Accumulated Other Comprehensive Income

PG&E Corporation and the Utility record the net periodic benefit cost for pension benefits and other benefits as a component of accumulated other comprehensive income, net of tax. Net periodic benefit cost is composed of unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax.

Regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets to reflect the difference between pension expense or income calculated in accordance with GAAP for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income for the pension benefits related to the Utility's defined benefit pension plan. To the extent the other benefits are in an overfunded position, the Utility records a regulatory liability related to its other benefits and long term disability costs, for the excess of cumulative income for ratemaking over cumulative other benefits expense calculated in accordance with GAAP, and a portion of the credit balance in accumulated other comprehensive income. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the charge remains in accumulated other comprehensive income (loss) for other benefits.

The estimated amounts that will be amortized into net periodic benefit costs for PG&E Corporation in 2014 are as follows:

Pension Benefit

(in millions)

Unrecognized prior service cost	\$	20
Unrecognized net loss		2
Total	\$	22

Other Benefits

(in millions)

Unrecognized prior service cost	\$	23
Unrecognized net loss		2
Total	\$	25

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

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2013	2012	2011	2013	2012	2011
Discount rate	4.89%	3.98%	4.66%	4.70 - 5.00%	3.75 - 4.08%	4.41 - 4.77%
Average rate of future compensation increases	4.00%	4.00%	5.00%	-	-	-
Expected return on plan assets	6.50%	5.40%	5.50%	3.50 - 6.70%	2.90 - 6.10%	4.40 - 5.50%

The assumed health care cost trend rate as of December 31, 2013 was 8%, decreasing gradually to an ultimate trend rate in 2020 and beyond of approximately 5%. A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on postretirement benefit obligation	\$ 86	\$ (88)
Effect on service and interest cost	9	(9)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on plan assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth added to a long-term inflation rate. For the pension plan, the assumed return of 6.5% compares to a ten-year actual return of 8.7%. The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of over approximately 494 Aa-grade non-callable bonds at December 31, 2013. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

Investment Policies and Strategies

The financial position of PG&E Corporation's and the Utility's funded employee benefit plans is driven by the relationship between plan assets and liabilities. As noted above, the funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funded status occurs when asset values change differently from liability values and can result in fluctuations in costs for financial reporting, as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trust's fixed-income portfolio market values, interest rate changes also influence liability valuations as discount rates move with current bond yields. To manage this risk, PG&E Corporation's and the Utility's trusts hold significant allocations to fixed-income investments that include U.S. government securities, corporate securities, and other fixed-income securities. Although they contribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. The equity investment allocation is implemented through portfolios that include common stock and commingled funds across multiple industry sectors. Real assets and absolute return investments are held to diversify the trust's holdings in equity and fixed-income investments by exhibiting returns with low correlation to the direction of these markets. Real assets include commodities futures, REITS, global listed infrastructure equities, and private real estate funds. Absolute return investments include hedge fund portfolios.

Target allocations for equity investments have generally declined in favor of longer-maturity fixed-income investments and real assets as a means of dampening future funded status volatility. Derivative instruments such as equity index futures contracts are used to maintain existing equity exposure while adding exposure to fixed-income securities. In addition, derivative instruments such as equity index futures and fixed income futures are used to rebalance the fixed income/equity allocation of the pension's portfolio. Foreign currency exchange contracts are also used to hedge a portion of the currency of the global equity investments.

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

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

	Pension Benefits			Other Benefits		
	2014	2013	2012	2014	2013	2012
Global equity securities	25%	25%	35%	30%	28%	38%
Absolute return	5%	5%	5%	3%	4%	4%
Real assets	10%	10%	10%	8%	8%	8%
Extended fixed-income securities	3%	3%	3%	-%	-%	-%
Fixed-income securities	57%	57%	47%	59%	60%	50%
Total	100%	100%	100%	100%	100%	100%

Fair Value Measurements

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2013 and 2012.

(in millions)	Fair Value Measurements							
	At December 31,							
	2013				2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Pension Benefits:								
Money market investments	\$ 70	\$ -	\$ -	\$ 70	\$ 112	\$ -	\$ -	\$ 112
Global equity securities	1,123	2,363	-	3,486	402	3,017	-	3,419
Absolute return	-	-	554	554	-	-	513	513
Real assets	562	-	544	1,106	525	-	285	810
Fixed-income securities:								
U.S. government	1,281	319	-	1,600	1,576	139	-	1,715
Corporate	1	4,230	625	4,856	3	4,275	611	4,889
Other	166	555	-	721	-	576	-	576
Total	\$ 3,203	\$ 7,467	\$ 1,723	\$ 12,393	\$ 2,618	\$ 8,007	\$ 1,409	\$ 12,034
Other Benefits:								
Money market investments	\$ 31	\$ -	\$ -	\$ 31	\$ 77	\$ -	\$ -	\$ 77
Global equity securities	127	504	-	631	118	397	-	515
Absolute return	-	-	53	53	-	-	49	49
Real assets	67	-	38	105	68	-	28	96
Fixed-income securities:								
U.S. government	119	5	-	124	148	5	-	153
Corporate	4	894	2	900	9	795	1	805
Other	14	37	-	51	-	38	-	38
Total	\$ 362	\$ 1,440	\$ 93	\$ 1,895	\$ 420	\$ 1,235	\$ 78	\$ 1,733
Total plan assets at fair value				\$ 14,288				\$ 13,767

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of \$131 million and \$132 million at December 31, 2013 and 2012, respectively. These net assets and net liabilities were comprised primarily of cash, accounts receivable, accounts payable, and deferred taxes.

Valuation Techniques

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

Money Market Investments

Money market investments consist primarily of commingled funds of U.S. government short-term securities that are considered Level 1 assets and valued at the net asset value of \$1 per unit. The number of units held by the plan fluctuates based on the unadjusted price changes in active markets for the funds' underlying assets.

Equity Securities

The global equity categories include equity investments in common stock and equity-index futures, and commingled funds comprised of equity across multiple industries and regions of the world. Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active markets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets. Collateral posted related to these futures consist of money market investments that are considered Level 1 assets. Commingled funds are valued using a net asset value per share and are maintained by investment companies for large institutional investors and are not publicly traded. Commingled funds are comprised primarily of underlying equity securities that are publicly traded on exchanges, and price quotes for the assets held by these funds are readily observable and available. Commingled funds are categorized as Level 2 assets.

Absolute Return

The absolute return category includes portfolios of hedge funds that are valued using a net asset value per share based on a variety of proprietary and non-proprietary valuation methods, including unadjusted prices for publicly-traded securities in active markets. Hedge funds are considered Level 3 assets.

Real Assets

The real asset category includes portfolios of commodities, commodities futures, global REITS, global listed infrastructure equities, and private real estate funds. The commodities, commodities futures, global REITS, and global listed infrastructure equities are actively traded on a public exchange and are therefore considered Level 1 assets. Collateral posted related to the commodities futures consist of money market investments that are considered Level 1 assets. Private real estate funds are valued using a net asset value per share derived using appraisals, pricing models, and valuation inputs that are unobservable and are considered Level 3 assets.

Fixed-Income

The fixed-income category includes U.S. government securities, corporate securities, and other fixed-income securities.

U.S. government fixed-income primarily consists of U.S. Treasury notes and U.S. government bonds that are valued based on quoted market prices or evaluated pricing data for similar securities adjusted for observable differences. These securities are categorized as Level 1 or Level 2 assets.

Corporate fixed-income primarily includes investment grade bonds of U.S. issuers across multiple industries that are valued based on a compilation of primarily observable information or broker quotes in non-active markets. The fair value of corporate bonds is determined using recently executed transactions, market price quotations (where observable), bond spreads or credit default swap spreads obtained from independent external parties such as vendors and brokers adjusted for any basis difference between cash and derivative instruments. These securities are classified as Level 2 assets. Corporate fixed-income also includes commingled funds that are valued using a net asset value per share and are comprised of corporate debt instruments. Commingled funds are considered Level 2 assets. Corporate fixed-income also includes privately secured debt portfolios which are valued using a net asset value per share using pricing models and valuation inputs that are unobservable and are considered Level 3 assets.

Other fixed-income primarily includes pass-through and asset-backed securities. Pass-through securities are valued based on benchmark yields created using observable market inputs and are Level 2 assets. Asset-backed securities are primarily valued based on broker quotes and are considered Level 2 assets. Other fixed-income also includes municipal bonds and index futures. Collateral posted related to the index futures consist of money market investments that are considered Level 1 assets. Municipal bonds are valued based on a compilation of primarily observable information or broker quotes in non-active markets and are considered Level 2 assets. Futures are valued based on unadjusted prices in active markets and are Level 1 assets.

Transfers Between Levels

Any transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. No significant transfers between levels occurred in the years ended December 31, 2013 and 2012.

Level 3 Reconciliation

The following table is a reconciliation of changes in the fair value of instruments for pension and other benefit plans that have been classified as Level 3 for the years ended December 31, 2013 and 2012:

(in millions)	Pension Benefits			
	Absolute Return	Corporate Fixed-Income	Real Assets	Total
Balance as of January 1, 2012	\$ 487	\$ 585	\$ 65	\$ 1,137
Actual return on plan assets:				
Relating to assets still held at the reporting date	26	28	12	66
Relating to assets sold during the period	-	(1)	-	(1)
Purchases, issuances, sales, and settlements				
Purchases	-	12	208	220
Settlements	-	(13)	-	(13)
Balance as of December 31, 2012	\$ 513	\$ 611	\$ 285	\$ 1,409
Actual return on plan assets:				
Relating to assets still held at the reporting date	37	1	49	87
Relating to assets sold during the period	4	-	(3)	1
Purchases, issuances, sales, and settlements				
Purchases	-	20	352	372
Settlements	-	(7)	(139)	(146)
Balance as of December 31, 2013	\$ 554	\$ 625	\$ 544	\$ 1,723

(in millions)	Other Benefits			
	Absolute Return	Corporate Fixed-Income	Real Assets	Total
Balance as of January 1, 2012	\$ 47	\$ 1	6	\$ 54
Actual return on plan assets:				
Relating to assets still held at the reporting date	2	-	1	3
Relating to assets sold during the period	-	-	-	-
Purchases, issuances, sales, and settlements				
Purchases	-	1	21	22
Settlements	-	(1)	-	(1)
Balance as of December 31, 2012	\$ 49	\$ 1	\$ 28	\$ 78
Actual return on plan assets:				
Relating to assets still held at the reporting date	4	-	3	7
Relating to assets sold during the period	-	-	-	-
Purchases, issuances, sales, and settlements				
Purchases	12	1	21	34
Settlements	(12)	-	(14)	(26)
Balance as of December 31, 2013	\$ 53	\$ 2	\$ 38	\$ 93

There were no transfers out of Level 3 in 2013 and 2012.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed \$323 million to the pension benefit plans and \$145 million to the other benefit plans in 2013. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2013. The Utility's pension benefits met all the funding requirements under ERISA. PG&E Corporation and the Utility expect to make total contributions of approximately \$327 million and \$71 million to the pension plan and other postretirement benefit plans, respectively, for 2014.

Benefits Payments and Receipts

As of December 31, 2013, the estimated benefits expected to be paid and the estimated federal subsidies expected to be received in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

(in millions)	Pension	Other	Federal Subsidy
2014	\$ 613	\$ 90	\$ (6)
2015	652	95	(7)
2016	692	100	(8)
2017	730	107	(8)
2018	766	113	(9)
2019 - 2023	4,326	609	(35)

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

Defined Contribution Benefit Plans

PG&E Corporation sponsors employee retirement savings plans, including a defined contribution savings plan that is qualified as a 401(k) plan under the Internal Revenue Code 1986, as amended. These plans permit eligible employees to defer compensation, to make pre-tax and after-tax contributions, and provide for employer contributions to be made to eligible participants. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income was as follows:

(in millions)	
Year ended December 31,	
2013	\$ 71
2012	67
2011	65

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

NOTE 12: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. The Utility is uncertain when and how the remaining disputed claims will be resolved.

Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

The following table presents the changes in the remaining net disputed claims liability, which includes interest:

(in millions)

Balance at December 31, 2012	\$	842
Interest accrued, net of settlement		25
Less: supplier settlements-principal amount		(3)
Balance at December 31, 2013	\$	864

At December 31, 2013 and 2012, the remaining net disputed claims liability consisted of \$154 million and \$157 million, respectively, of remaining net disputed claims (classified on the Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and \$710 million and \$685 million, respectively, of accrued interest (classified on the Consolidated Balance Sheets within interest payable).

At December 31, 2013 and 2012, the Utility held \$291 million, respectively, in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Consolidated Balance Sheets.

Interest accrues on the remaining net disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers in rates, these collections are not held in escrow. If the amount of accrued interest is greater than the amount of interest ultimately determined to be owed on the remaining net disputed claims, the Utility would refund to customers any excess interest collected. The amount of any interest that the Utility may be required to pay will depend on the final determined amount of the remaining net disputed claims and when such interest is paid.

NOTE 13: RELATED PARTY AGREEMENTS AND TRANSACTIONS

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

The Utility's significant related party transactions were:

(in millions)	Year Ended December 31,		
	2013	2012	2011
Utility revenues from:			
Administrative services provided to PG&E Corporation	\$ 7	\$ 7	\$ 6
Utility expenses from:			
Administrative services received from PG&E Corporation	\$ 45	\$ 50	\$ 49
Utility employee benefit due to PG&E Corporation	57	51	33

At December 31, 2013 and 2012, the Utility had receivables of \$22 million and \$19 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables of \$17 million, each year respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

NOTE 14: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to natural gas matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. PG&E Corporation also has financial commitments described under “Other Commitments” below.

Natural Gas Matters

On September 9, 2010, a natural gas transmission pipeline owned and operated by the Utility ruptured in San Bruno, California. The ensuing explosion and fire resulted in the deaths of eight people, numerous personal injuries, and extensive property damage. 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 the ongoing regulatory proceedings, investigations, and civil lawsuits that commenced following the San Bruno accident.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility that 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.

The SED has issued investigative reports and briefs in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations. In July 2013, the SED recommended that the CPUC impose what the SED characterizes as a penalty of \$2.25 billion on the Utility, allocated as follows: (1) \$300 million as a fine to the State General Fund, (2) \$435 million for a portion of costs related to the Utility’s PSEP that were previously disallowed by the CPUC and funded by shareholders, and (3) \$1.515 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future costs. (See “Disallowed Capital Costs” below.) Other parties, including the City of San Bruno, TURN, the CPUC’s ORA, and the City and County of San Francisco, have recommended total penalties of at least \$2.25 billion, including fines payable to the State General Fund of differing amounts.

The ALJs who oversee the investigations are expected to issue one or more presiding officers’ decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when the decisions will be issued. Based on the CPUC’s rules, the presiding officer’s decisions would become the final decisions of the CPUC 30 days after issuance unless the Utility or another party filed an appeal with the CPUC, or a CPUC commissioner requested that the CPUC review the decision, within such time. If an appeal or review request is filed, other parties would have 15 days to provide comments but the CPUC could act before considering any comments.

At December 31, 2013, the Consolidated Balance Sheets included an accrual of \$200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including how the total number and duration of violations will be determined; how the various penalty recommendations made by the SED and other parties will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility’s costs to perform any required remedial actions will be considered; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on PG&E Corporation’s and the Utility’s financial condition, results of operations, and cash flows. The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow PSEP costs that were previously authorized for recovery or other future costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See “Disallowed Capital Costs” below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

Other CPUC Enforcement Matters

PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses that may be incurred in connection with the following matters.

Gas Safety Citation Program. The Utility and other California gas corporations are required to provide notice to the SED of any self-identified or self-corrected violations of certain state and federal regulations that relate to the safety of their natural gas facilities and operating practices. The SED is authorized to issue citations and impose fines for self-identified or self-corrected violations and for violations that the SED identifies through its periodic audits of the Utility's operations or otherwise. The SED can exercise its discretion in determining whether to impose fines and the amount of such fines, or whether to take other enforcement action, based on the totality of the circumstances. The SED can consider such factors as 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. In January 2012, the SED imposed fines of \$16.8 million on the Utility for self-reported failure to perform certain leak surveys and in 2013 the SED imposed fines ranging from \$50,000 to \$8.1 million for self-reported violations. The Utility has filed over 50 self-reports with the SED, plus additional follow-up reports, that the SED has not yet addressed. The SED is expected to impose fines or take enforcement action with respect to some of these self-reports.

Natural Gas Transmission Pipeline Rights-of-Way. In 2012, the Utility notified the CPUC and the SED that it is undertaking a system-wide effort to survey its transmission pipelines and identify and remove encroachments (such as building structures and vegetation overgrowth) from pipeline rights-of-way over a multi-year period. The SED could impose fines on the Utility or take other enforcement action in connection with this matter.

Orders to Show Cause. In August 2013, the CPUC issued two OSCs related to a document submitted by the Utility on July 3, 2013 as "errata" to correct information about some segments in Lines 101 and 147 (two of the Utility's natural gas transmission pipelines that serve the San Francisco peninsula) that had been previously provided to the CPUC in October 2011 to allow the Utility to restore operating pressure on these pipelines. On December 19, 2013, the CPUC issued a decision to impose fines of approximately \$14 million on the Utility in connection with the errata submission, finding that the Utility violated CPUC rules that prohibit any person from misleading the CPUC. The Utility recorded this amount as an expense for 2013. On January 23, 2014, the Utility filed an application for the rehearing of this decision, arguing that it is erroneous in several respects. It is uncertain when the CPUC will issue a decision on the other OSC that directed the Utility to show cause why all orders issued by the CPUC to authorize increased operating pressure on the Utility's gas transmission pipelines should not be immediately suspended pending competent demonstration that the Utility's natural gas system records are reliable. Briefing on this OSC was completed on January 31, 2014.

Disallowed Capital Costs

In 2011, the CPUC ordered all natural gas operators in California to submit proposed plans to modernize and upgrade their natural gas transmission systems as well as associated cost forecasts and ratemaking proposals. In December 2012, the CPUC approved most of the projects proposed in the Utility's PSEP application that was filed in August 2011, but disallowed the Utility's request for rate recovery of a significant portion of costs the Utility forecasted it would incur through 2014. In October 2013, the Utility updated its PSEP application to present the results of its completed search and review of records relating to validation of operating pressure for all of the approximately 6,750 miles of the Utility's natural gas transmission pipelines. The Utility requested that the CPUC approve changes to the scope and prioritization of PSEP work, including deferring some projects to after 2014 and accelerating other projects, and that the CPUC adjust authorized revenue requirements to reflect these changes. The Utility has requested that the CPUC issue a final decision by August 2014.

At December 31, 2013, the Utility has recorded cumulative charges of \$549 million for PSEP capital costs that are expected to exceed the amount to be recovered. The Utility has requested that the CPUC authorize capital costs of \$766 million under the PSEP, reflecting the proposed changes in the PSEP update application. Of this amount, approximately \$280 million is recorded in Property, Plant, and Equipment on the Consolidated Balance Sheets at December 31, 2013. The Utility could record additional charges to the extent PSEP capital costs are higher than currently expected, or if additional capital costs are disallowed by the CPUC. The Utility's ability to recover PSEP capital costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

Criminal Investigation

In June 2011, the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office began an investigation of the San Bruno accident and indicated that the Utility is a target of the investigation. Although the San Mateo County District Attorney's Office has publicly indicated that it will not pursue state criminal charges, the U.S. Department of Justice may still bring criminal charges, including charges based on claims that the Utility violated the federal Pipeline Safety Act, against PG&E Corporation or the Utility. It is uncertain whether any criminal charges will be brought against any of PG&E Corporation's or the Utility's current or former employees. The Utility is continuing to cooperate with federal investigators. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses associated with any civil or criminal penalties that could be imposed and such penalties could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, the Utility's business or operations could be negatively affected by any remedial measures that the Utility may undertake, such as operating its natural gas transmission business subject to the supervision and oversight of an independent monitor.

Third-Party Liability Claims

The Utility has settled the claims of substantially all of the remaining plaintiffs who sought compensation for personal injury and property damage, and other relief, including punitive damages, following the San Bruno accident. (Approximately 165 lawsuits on behalf of approximately 525 plaintiffs have been filed against the Utility.) At December 31, 2013, the Utility has recorded cumulative charges of \$565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident and has made cumulative payments of \$520 million for settlements. In addition, the Utility has incurred cumulative expenses of \$86 million for associated legal costs. The Utility's liability for third-party claims is included in other current liabilities in the Consolidated Balance Sheets and totaled \$45 million at December 31, 2013 and \$146 million at December 31, 2012.

The aggregate amount of insurance coverage for third-party liability attributable to the San Bruno accident is approximately \$992 million in excess of a \$10 million deductible. Through December 31, 2013, the Utility has recognized cumulative insurance recoveries of \$354 million for third-party claims and associated legal costs. These amounts were recorded as a reduction to operating and maintenance expense in the Consolidated Statements of Income. Although the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal costs) relating to the San Bruno accident will ultimately be recovered through its insurance, it is unable to predict the amount and timing of additional insurance recoveries.

Class Action Complaint

On August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than \$100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages.

PG&E Corporation and the Utility contest the plaintiffs' allegations. On May 23, 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

Other Legal and Regulatory Contingencies

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

Accruals for other legal and regulatory contingencies (excluding amounts related to natural gas matters above) totaled \$43 million at December 31, 2013 and \$34 million at December 31, 2012. These amounts are included in other current liabilities in the Consolidated Balance Sheets. The estimated reasonably possible range of loss for these matters in excess of the recorded accrual is not material. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Environmental Remediation Contingencies

The Utility is required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include 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. 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.

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. The Utility records an environmental remediation liability when the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated probable costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The following table presents the changes in the environmental remediation liability:

(in millions)	
Balance at December 31, 2012	\$ 910
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	116
Amounts not recoverable from customers	49
Less: Payments	(175)
Balance at December 31, 2013	<u>\$ 900</u>

The environmental remediation liability is primarily included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

(in millions)	Balance at December 31,	
	2013	2012
Utility-owned natural gas compressor site near Hinkley, California ⁽¹⁾	\$ 190	\$ 226
Utility-owned natural gas compressor site near Topock, Arizona ⁽¹⁾	264	239
Utility-owned generation facilities (other than for fossil fuel-fired), other facilities, and third-party disposal sites	160	158
Former MGP sites owned by the Utility or third parties	184	181
Fossil fuel-fired generation facilities and sites	102	106
Total environmental remediation liability	<u>\$ 900</u>	<u>\$ 910</u>

⁽¹⁾ See "Natural Gas Compressor Sites" below.

At December 31, 2013, the Utility expected to recover \$579 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

Natural Gas Compressor 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 sites near Hinkley, California and Topock, Arizona. The Utility is also required to take measures to abate the effects of the contamination on the environment.

Hinkley Site

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. On July 17, 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue the final project permits and a final clean-up order in phases through 2014 and into 2015. As the permits and order are issued, the Utility will obtain additional clarity on the total costs associated with the final remedy and related activities. In January 2014, the Regional Board also approved an updated background study plan prepared in consultation with the U.S. Geological Survey, the results of which will define the final cleanup standards. The background study is not expected to be complete until 2018.

The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provided replacement water to affected residents. As of December 31, 2013, approximately 380 residential households located near the plume boundary were covered by the Utility's whole house water replacement program and the majority have opted to accept the Utility's offer to purchase their properties. The Utility is required to maintain and operate the program for five years or until the State of California has adopted a drinking water standard specifically for hexavalent chromium at which time the program will be evaluated. The State of California recently proposed draft regulations for hexavalent chromium and is expected to issue a final standard by June 2014.

The Utility's environmental remediation liability at December 31, 2013 reflects the Utility's best estimate of probable future costs associated with its final remediation plan, interim remediation measures, and whole house water program. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, the extent of the chromium plume boundary, and adoption of a final drinking water standard by the State of California. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The California Department of Toxic Substances Control has approved the Utility's final remediation plan to contain and remediate the underground plume of hexavalent chromium, under which the Utility will implement an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility expects to submit its final remedial design plan in 2014 for approval to begin construction of the groundwater treatment system. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River.

The Utility's environmental remediation liability at December 31, 2013 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as \$1.7 billion (including amounts related to the Hinkley and Topock sites described above) 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. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to \$3.2 billion per nuclear incident and \$2 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to \$131 million of coverage for nuclear and non-nuclear property damages.

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

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to \$13.6 billion. The Utility purchased the maximum available public liability insurance of \$375 million for Diablo Canyon. The balance of the \$13.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to \$255 million per nuclear incident under this program, with payments in each year limited to a maximum of \$38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018.

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of \$375 million per incident. In addition, the Utility has \$53 million of liability insurance for Humboldt Bay Unit 3 and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the liability insurance.

Commitments

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or electricity at the date of delivery. The costs incurred for all power purchases and electric capacity were as follows:

(in millions)	2013	2012	2011
Qualifying facilities ⁽¹⁾	\$ 813	\$ 779	\$ 1,069
Renewable energy contracts	1,281	815	622
Other power purchase agreements	902	661	690

⁽¹⁾ Costs incurred include \$ 271 , \$286, and \$297 attributable to renewable energy contracts with qualifying facilities at December 31, 2013 , 2012 , and 2011 , respectively.

Qualifying Facility Power Purchase Agreement – The Utility has entered into agreements to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. As of December 31, 2013, the Utility had agreements with 170 QFs that are in operation, which expire at various dates between 2014 and 2028.

Renewable Energy Power Purchase Agreements – The Utility is required to gradually increase the amount of renewable energy that it delivers to its customers in order to comply with California’s renewable portfolio standard requirement. The Utility has entered into various contracts to purchase renewable energy to help meet the renewable portfolio standard requirement. The Utility’s obligations under a significant portion of these agreements are contingent on the third party’s construction of new generation facilities. The Utility’s commitments for energy payments under these renewable energy agreements are expected to grow significantly.

Other Power Purchase Agreements – The Utility has entered into several power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility’s obligation under a portion of these agreements is contingent on the third parties’ development of new generation facilities to provide capacity and energy products to the Utility. The Utility also has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

At December 31, 2013, the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones were as follows:

(in millions)	Qualifying Facility	Renewable (Other than QFs)	Other	Total Payments
2014	\$ 913	\$ 1,906	\$ 829	\$ 3,648
2015	707	2,102	770	3,579
2016	587	2,109	722	3,418
2017	450	2,104	684	3,238
2018	406	1,962	640	3,008
Thereafter	1,614	30,242	2,984	34,840
Total	\$ 4,677	\$ 40,425	\$ 6,629	\$ 51,731

The following table shows the future fixed capacity payments due under QF agreements that are treated as capital leases. (These amounts are also included in the table above.) These payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. These capital lease QF agreements expire between April 2014 and September 2021. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2014	\$ 27
2015	24
2016	22
2017	18
2018	12
Thereafter	8
Total fixed capacity payments	111
Less: amount representing interest	14
Present value of fixed capacity payments	\$ 97

Minimum lease payments associated with the lease obligations are included in the Utility's cost of electricity. The timing of the recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity.

The present value of the fixed capacity payments due under these agreements is recorded on the Consolidated Balance Sheets. At December 31, 2013 and 2012, current liabilities – other included \$23 million and \$29 million, respectively, and noncurrent liabilities – other included \$74 million and \$96 million, respectively. The corresponding assets at December 31, 2013 and 2012 of \$97 million and \$125 million including accumulated amortization of \$176 million and \$148 million, respectively are included in property, plant, and equipment on the Consolidated Balance Sheets.

Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada, the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for natural gas storage services in northern California in order to more reliably meet customers' loads.

At December 31, 2013, the Utility's undiscounted future expected payment obligations for natural gas supplies, transportation and storage were as follows:

(in millions)

2014	\$	727
2015		198
2016		150
2017		108
2018		108
Thereafter		756
Total	\$	2,047

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage, which include contracts less than 1 year, amounted to \$1.6 billion in 2013, \$1.3 billion in 2012, and \$1.8 billion in 2011.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have remaining terms ranging from one to 12 years and are intended to ensure long-term nuclear fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2020, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

At December 31, 2013, the undiscounted future expected payment obligations for nuclear fuel were as follows:

(in millions)

2014	\$	145
2015		162
2016		146
2017		148
2018		132
Thereafter		647
Total	\$	1,380

Payments for nuclear fuel amounted to \$162 million in 2013, \$118 million in 2012, and \$77 million in 2011.

Other Commitments

PG&E Corporation and the Utility have other commitments relating to operating leases. At December 31, 2013, the future minimum payments related to these commitments were as follows:

(in millions)

2014	\$	42
2015		37
2016		34
2017		27
2018		24
Thereafter		193
Total	\$	357

Payments for other commitments relating to operating leases amounted to \$40 million in 2013, \$32 million in 2012, and \$27 million in 2011. PG&E Corporation and the Utility had operating leases on office facilities expiring at various dates from 2014 to 2023. Certain leases on office facilities contain escalation clauses requiring annual increases in rent ranging from 2% to 5%. The rentals payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension options ranging between one and five years.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended			
	December 31	September 30	June 30	March 31
2013				
PG&E CORPORATION				
Operating revenues	\$ 3,975	\$ 4,175	\$ 3,776	\$ 3,672
Operating income	333	291	636	502
Income tax (benefit) provision	25	(24)	153	114
Net income	90	164	332	242
Income available for common shareholders	86	161	328	239
Comprehensive income	210	165	352	252
Net earnings per common share, basic	0.19	0.36	0.74	0.55
Net earnings per common share, diluted	0.19	0.36	0.74	0.55
Common stock price per share:				
High	42.75	46.37	48.44	44.53
Low	40.07	40.76	43.59	40.47
UTILITY				
Operating revenues	\$ 3,973	\$ 4,174	\$ 3,775	\$ 3,671
Operating income	360	292	635	503
Income tax (benefit) provision	65	(20)	160	121
Net income	138	162	329	237
Income available for common stock	134	159	325	234
Comprehensive income	231	166	333	242
2012				
PG&E CORPORATION				
Operating revenues	\$ 3,830	\$ 3,976	\$ 3,593	\$ 3,641
Operating income	125	614	467	487
Income tax (benefit) provision	(54)	100	87	104
Net income (loss)	(9)	364	239	236
Income (loss) available for common shareholders	(13)	361	235	233
Comprehensive income	77	372	247	246
Net earnings (loss) per common share, basic	(0.03)	0.84	0.56	0.56
Net earnings (loss) per common share, diluted	(0.03)	0.84	0.55	0.56
Common stock price per share:				
High	43.48	46.51	45.20	43.72
Low	39.71	42.41	42.04	40.16
UTILITY				
Operating revenues	\$ 3,829	\$ 3,974	\$ 3,592	\$ 3,640
Operating income	127	613	467	488
Net income	13	340	227	231
Income tax provision	(30)	122	93	113
Income available for common stock	9	337	223	228
Comprehensive income	96	348	235	241

The Utility recorded a charge to net income of \$196 million in the third quarter of 2013 and \$353 million during the fourth quarter 2012, for disallowed capital expenditures associated with the Utility's pipeline safety enhancement plan. See Note 14 of the Notes to the Consolidated Financial Statements.

The Utility recorded a provision of \$110 million and \$80 million in the third quarter 2013 and in the second quarter 2012, respectively, for estimated third-party claims related to the San Bruno accident. During the second quarter 2013 and third quarter 2013, the Utility recognized \$45 million and \$25 million, respectively, for insurance claims. During the first quarter 2012, second quarter of 2012, third quarter of 2012, and fourth quarter 2012 the Utility recognized \$11 million, \$25 million, \$99 million, and \$50 million, respectively, for insurance recoveries. See Note 14 of the Notes to the Consolidated Financial Statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2013.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2013 and 2012, and the Company's related consolidated statements of income, comprehensive income, equity, and cash flows and the Utility's related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 14 to the consolidated financial statements, there are three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control—Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 11, 2014 expressed an unqualified opinion on the Company's and the Utility's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 11, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company
San Francisco, California

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and the Utility and our report dated February 11, 2014 expressed an unqualified opinion on those financial statements and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 11, 2014

Significant Subsidiaries

Parent of Significant Subsidiary	Name of Significant Subsidiary	Jurisdiction of Formation of Subsidiary	Names under which Significant Subsidiary does business
PG&E Corporation	Pacific Gas and Electric Company	CA	Pacific Gas and Electric Company PG&E
Pacific Gas and Electric Company	None		

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-172393 on Form S-3, 333-144498 on Form S-3D, and 333-73054, 333-129422 and 333-176090 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-172394 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 11, 2014, relating to the consolidated financial statements of PG&E Corporation and subsidiaries (“the Company”) and Pacific Gas and Electric Company and subsidiaries (the “Utility”) (which report expresses an unqualified opinion and includes an explanatory paragraph relating to three investigative enforcement proceedings pending with the California Public Utilities Commission that may result in material amounts of penalties), the consolidated financial statement schedules of the Company and the Utility, and the effectiveness of the Company’s and the Utility’s internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2013.

/s/ DELOITTE & TOUCHE LLP

February 11, 2014
San Francisco, California

POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2013 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February, 2014.

/s/ LEWIS CHEW

Lewis Chew

/s/ ROGER H. KIMMEL

Roger H. Kimmel

/s/ C. LEE COX

C. Lee Cox

/s/ RICHARD A. MESERVE

Richard A. Meserve

/s/ ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.

/s/ FORREST E. MILLER

Forrest E. Miller

/s/ FRED J. FOWLER

Fred J. Fowler

/s/ ROSENDO G. PARRA

Rosendo G. Parra

/s/ MARYELLEN C. HERRINGER

Maryellen C. Herringer

/s/ BARBARA L. RAMBO

Barbara L. Rambo

Richard C. Kelly

/s/ BARRY LAWSON WILLIAMS

Barry Lawson Williams

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2013 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February, 2014.

/s/ LEWIS CHEW

Lewis Chew

/s/ C. LEE COX

C. Lee Cox

/s/ ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.

/s/ FRED J. FOWLER

Fred J. Fowler

/s/ MARYELLEN C. HERRINGER

Maryellen C. Herringer

/s/ CHRISTOPHER P. JOHNS

Christopher P. Johns

Richard C. Kelly

/s/ ROGER H. KIMMEL

Roger H. Kimmel

/s/ RICHARD A. MESERVE

Richard A. Meserve

/s/ FORREST E. MILLER

Forrest E. Miller

/s/ ROSENDO G. PARRA

Rosendo G. Parra

/s/ BARBARA L. RAMBO

Barbara L. Rambo

/s/ BARRY LAWSON WILLIAMS

Barry Lawson Williams

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.

Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Kent M. Harvey, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

KENT M. HARVEY

Kent M. Harvey

Senior Vice President and Chief Financial Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

CHRISTOPHER P. JOHNS

Christopher P. Johns
President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2013 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2014

DINYAR B. MISTRY

Dinyar B. Mistry

Vice President, Chief Financial Officer, and Controller

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2013 ("Form 10-K"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ANTHONY F. EARLEY, JR.

ANTHONY F. EARLEY, JR.

Chairman, Chief Executive Officer and President

February 11, 2014

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2013 ("Form 10-K"), I, Kent M. Harvey, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

KENT. M. HARVEY

KENT M. HARVEY
Senior Vice President and
Chief Financial Officer

February 11, 2014

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2013 ("Form 10-K"), I, Christopher P. Johns, President of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JOHNS
CHRISTOPHER P. JOHNS
President

February 11, 2014

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the quarter ended September 30, 2013 ("Form 10-K"), I, Dinyar B. Mistry, Vice President, Chief Financial Officer, and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DINYAR B. MISTRY

DINYAR B. MISTRY

Vice President, Chief Financial Officer, and Controller

February 11, 2014
