PACIFIC GAS & ELECTRIC Co
Form 10-K
February 21, 2013

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

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2012

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) 267-7000 (Registrant's telephone number, including area code)	77 Beale Street, P.O. Box 770000 San Francisco, California 94177 (Address of principal executive offices) (Zip Code) (415) 973-7000 (Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5%	NYSE Amex Equities

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

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

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

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

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

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

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

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

PG&E Corporation	þ
Pacific Gas and Electric Company	þ

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

PG&E Corporation	Pacific Gas and Electric Company
Large accelerated filer þ	Large accelerated filer
Accelerated filer	Accelerated filer
Non-accelerated filer	Non-accelerated filer þ
Smaller reporting company	Smaller reporting company

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

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

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2012, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$19,276 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 11, 2013:

PG&E Corporation:	431,436,673
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 2012 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 2013 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

Item 1. Business

General

Corporate Structure and Business

PG&E Corporation, incorporated in California in 1995, is a holding company that conducts its business through Pacific Gas and Electric Company ("Utility"), 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 Utility served approximately 5.2 million electricity distribution customers and approximately 4.4 million natural gas distribution customers at December 31, 2012. The Utility had approximately $52 billion in assets at December 31, 2012 and generated revenues of approximately $15 billion in 2012. The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

Corporate and Other Information

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) 267-7000 and the Utility's telephone number is (415) 973-7000. PG&E Corporation and the Utility file or furnish various reports with the Securities and Exchange Commission ("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 Securities Exchange Act of 1934, as amended ("1934 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, 2012, which is attached to this report as Exhibit 13 ("2012 Annual Report") and the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders. The 2012 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 2012 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" ("MD&A").

Operational Improvements

The Utility's electricity and natural gas businesses are each led by a senior executive who reports to the President of the Utility. During 2012, the Utility continued to build these organizations by adding new leaders with extensive industry expertise and expanding the Utility's work force where needed to implement the Utility's enhanced focus on safety and operational excellence. Significant improvements were made to the Utility's natural gas operations during 2012 to enhance safety, test and replace pipelines, modernize and upgrade the system, and search and validate records. Much of this work was carried out under the Utility's pipeline safety enhancement plan that was approved by the CPUC in late December 2012. The Utility also continued work to implement the safety recommendations made by the National Transportation Safety Board ("NTSB") in its 2011 investigative report on 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.) The Utility also undertook significant projects in 2012 to improve and modernize its electricity operations by repairing, replacing or upgrading equipment to improve reliability and safety. In addition, the Utility continued the installation of advanced electric and gas meters throughout its service territory and took other 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 (such as distributed generation and storage, rooftop solar and other intermittent energy sources), and to enable the continued safe and reliable operation of the grid. (For more information, see “Electric Utility Operations” below.)

Employees

At December 31, 2012, PG&E Corporation and its subsidiaries had 20,593 regular employees, including 20,583 regular employees of the Utility. Of the Utility’s regular employees, 12,492 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO (“IBEW”); the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC (“ESC”); and the Service Employees International Union, Local 24/7 (“SEIU”). There are two collective bargaining agreements with IBEW. One IBEW collective bargaining agreement expires on December 31, 2014 and the other IBEW collective bargaining agreement expires on December 31, 2015. The ESC collective bargaining agreement expires on December 31, 2014. The SEIU collective bargaining agreement expires on July 31, 2013.

Regulatory Environment

Various aspects of the Utility's business are 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. These summaries are not an exhaustive description of all the laws, regulations, and regulatory proceedings that affect the Utility. The energy laws, regulations, and regulatory proceedings may change or be implemented or applied in a way that PG&E Corporation and the Utility do not currently anticipate.

PG&E Corporation is a public utility holding company that is subject to the requirements of the Public Utility Holding Company Act of 2005 (“PUHCA”). Under the PUHCA, public utility holding companies fall principally under the regulatory oversight of the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the PUHCA other than the obligation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes. These books and records provisions are largely duplicative of other provisions under the Federal Power Act of 1935 and state law.

For discussion of specific pending regulatory proceedings and investigations 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 2012 Annual Report, which information is incorporated herein by reference.

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 California Independent System Operator Corporation (“CAISO”), and the terms and rates of wholesale electricity sales. The FERC has authority to impose penalties of up to $1 million per day for violation of certain federal statutes, including the Federal Power Act of 1935 and the Natural Gas Act of 1938, and for violations of FERC-approved regulations. The FERC has jurisdiction over the Utility's electricity transmission annual amount of revenue (“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 North American Electric Reliability Corporation ("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 ("WECC"). 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. In addition, the WECC and the NERC may perform spot checks or other interim audits, reports, or investigations. The FERC also has authorized the WECC and the NERC to impose penalties 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 ("Humboldt Bay Unit 3"). 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 2012 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 Pipeline and Hazardous Materials Safety Administration ("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. Through a certification with PHMSA, the CPUC is authorized 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 penalties 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 also 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, and the reduction of greenhouse gas (“GHG”) emissions. 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 penalties 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 2012 Annual Report for information about the CPUC’s pending enforcement proceedings against the Utility relating to the Utility’s safety recordkeeping for its natural gas transmission system; the Utility’s operation of its natural gas transmission pipeline system in or near locations of higher population density; and 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, which discussion is incorporated herein by reference.)

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 complex and detailed rules governing transactions between California's electricity and gas utilities and certain of their affiliates. The rules address the use of the utilities’ names and logos by their affiliates, the separation of utilities and their affiliates, provision of utility information to affiliates, and energy procurement-related transactions between the utilities and their affiliates. The CPUC has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the California Energy Commission (“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. In addition, the CEC 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 California Air Resources Board (“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 California Global Warming Solutions Act of 2006 (“AB 32”), which requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2013. In October 2011, the CARB adopted its final “cap-and-trade” regulations to help gradually reduce GHG emissions. In November 2012, the CARB held the first auction of GHG emission allowances under this “cap-and-trade” program. (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. Some licenses and permits may be revoked or modified by the agency that granted them if facts develop or events occur that differ significantly from the facts and projections assumed when they were granted. In addition, 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. (For more information, see “Environmental Matters — Water Quality” below.)

The Utility has franchise agreements with 292 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. Under these permits, authorizations, and licenses, the Utility has 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.

At the state level, the California Legislature mandated the restructuring of the California electricity industry beginning in 1998 to allow customers of the California investor-owned electric utilities to purchase electricity from a service provider other than the regulated utilities (the ability to choose an energy provider is referred to as “direct access”). A market framework was established for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity through transactions conducted through the California Power Exchange (“PX”). As the 2000-2001 California energy crisis unfolded, direct access was suspended. The PX filed a petition for bankruptcy protection and now operates solely to reconcile remaining refund amounts owed and to make compliance filings as required by the FERC in the California refund proceeding, which is still pending at the FERC. (For information about the status of the California refund proceeding and the remaining disputed claims made by power suppliers in the Utility’s bankruptcy proceeding that was precipitated by the energy crisis, see Note 13: Resolution of Remaining Chapter 11 Disputed Claims, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.)

Current California law provides only limited opportunities for customers who receive “bundled” electricity service (i.e., electricity, transmission and distribution services) to choose to purchase electricity directly from an energy service provider other than the three California investor-owned electric utilities. As authorized by California law enacted in October 2009, the CPUC has adopted a plan to reopen direct access on a limited and gradual basis to allow eligible customers of the three California investor-owned electric utilities to purchase electricity from independent electric service providers rather than from a utility. Effective April 2010, all qualifying non-residential customers became eligible to take direct access service subject to annual and absolute caps. It is estimated that the total amount of direct access that will be allowed in the Utility's service territory by the end of the four-year phase-in period will be equal to approximately 11% of the Utility's total annual retail sales at the end of the period, roughly the highest level that was reached before the CPUC suspended direct access. Further legislative action is required to exceed these limits.

In addition, the Utility's customers may, under certain circumstances, obtain power from a community choice aggregator ("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. Over 90,000 customers in Marin County are now receiving commodity service from the Marin Energy Authority, a CCA.

In some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, seek to acquire the Utility's distribution facilities. For example South San Joaquin Irrigation District ("SSJID") has applied to San Joaquin County Local Agency Formation Commission for the authority to provide electric distribution service in and around the cities of Manteca, Ripon and Escalon. SSJID has indicated that, if it receives the requested authority, 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.

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 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. 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'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 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.

Ratemaking Mechanisms

Overview

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 revenue requirements that the Utility is authorized to collect from its customers. The CPUC determines the Utility's revenue requirements associated with electricity and natural gas distribution operations, electricity generation, and natural gas transportation and storage. The FERC determines the Utility's revenue requirements associated with its electricity transmission operations.

Revenue requirements are designed to allow a utility an opportunity to recover its reasonable operating and capital costs of providing utility services as well as a return of, and a fair rate of return on its investment in utility facilities ("rate base"). Revenue requirements are primarily determined based on the Utility's forecast of future costs. These costs include the Utility's costs of electricity and natural gas purchased for its customers, operating expenses, administrative and general expenses, depreciation, taxes, and public purpose programs.

To develop retail rates, the revenue requirements are allocated among customer classes which are mainly residential, commercial, industrial, and agricultural. Specific rate components are designed to produce the required revenue. 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.

The Utility uses balancing accounts to keep track of its authorized revenue requirements, actual customer billings collected through rates, and actual costs incurred to provide electricity and natural gas services. Balances in all CPUC-authorized accounts are subject to review, verification audit, and adjustment, if necessary, by the CPUC. For more information regarding the Utility's balancing accounts, see Note 3: Regulatory Assets, Liabilities and Balancing Accounts, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

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.

Electricity and Natural Gas Distribution and Electricity Generation Operations

General Rate Cases

The General Rate Case ("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 business and operational 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. Typical interveners in the Utility's GRC include the CPUC's Division of Ratepayer Advocates and The Utility Reform Network. In November 2012, the Utility filed its 2014 GRC application with the CPUC for rates effective from 2014 through 2016. For more information see the heading within MD&A entitled "2014 General Rate Case" in the 2012 Annual Report, which information is incorporated herein by reference.

Attrition Rate Adjustments

The CPUC may authorize the Utility to receive annual increases for the years between GRCs in the base revenues authorized for the test year of a GRC in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that the Utility is authorized to collect in rates for electricity and natural gas distribution and electricity generation operations.

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 electricity and natural gas distribution, natural gas transmission, and electricity generation assets. The authorized capital structure that was in effect through 2012 consisted of 52% equity, 46% long-term debt, and 2% preferred stock. Since 2008, the Utility’s authorized cost of capital has been subject to an adjustment mechanism that is triggered in a particular year if the 12-month October-through-September average of the applicable Moody's Investors Service utility bond index increases or decreases by more than 100 basis points from the benchmark. If the adjustment mechanism is triggered, the Utility’s authorized ROE beginning on the next January 1st would be adjusted by one-half of the increase or decrease. This mechanism did not trigger a change in the Utility’s authorized rates of return for 2012.

In December 2012, the CPUC issued a decision in the cost of capital proceeding that authorizes the Utility to maintain a capital structure consisting of 52% equity, 47% long-term debt, and 1% preferred stock beginning on January 1, 2013. (For more information see the section of MD&A entitled “2013 Cost of Capital Proceeding” in the 2012 Annual Report, which information is incorporated herein by reference.)

Rate Recovery of Costs of Electricity Generation Resources

Overview

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 reduce GHG emissions and 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 Energy Resource Recovery Account (“ERRA”), a balancing account authorized by the CPUC. The ERRA tracks the difference between (1) billed and unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility's authorized procurement plans. To determine the rates used to collect ERRA revenues, each year, 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 20, 2012, the CPUC approved the Utility’s forecast of 2013 procurement costs and associated revenue requirement. Changes in rates to reflect the approved revenue requirement became effective on January 1, 2013. (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. The CPUC also authorized the Utility to recover fixed and variable 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 CPUC-authorized revenue requirements to recover the initial capital costs for utility-owned generation projects are recovered through the Utility Generation Balancing Account ("UGBA"), which tracks the difference between the CPUC-approved forecast of initial capital costs, adjusted from time to time as permitted by the CPUC, and actual costs. The initial revenue requirement for Utility-owned projects generally would begin to accrue in the UGBA as of the new facility's commercial operation date or the date a completed facility is transferred to the Utility, and would be included in rates on January 1 of the following year. The CPUC-authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for operating Utility-owned generation facilities are addressed in the Utility's GRC.

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 transmission owner 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 transmission owner 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.

Transmission Owner 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 transmission owner rate case ("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 "FERC Transmission Owner Rate Case" in the 2012 Annual Report, which information is incorporated herein by reference.

The Utility's transmission owner 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

Gas Safety Rulemaking Proceeding

The CPUC is conducting a rulemaking proceeding to adopt new safety and reliability regulations for natural gas transmission and distribution pipelines in California and the related ratemaking mechanisms. As directed by the CPUC, in August 2011, the Utility filed its proposed pipeline safety enhancement plan to replace certain natural gas pipeline segments, install automatic or remote shut-off valves, and take other actions to modernize and upgrade its natural gas transmission system. On December 20, 2012, the CPUC approved the Utility's proposed plan but disallowed the Utility's request for rate recovery of a significant portion of plan-related costs that the Utility forecasted it would incur over the first phase of the plan (2011 through 2014). See the information under the heading within MD&A entitled "Natural Gas Matters–CPUC Gas Safety Rulemaking Proceeding" in the 2012 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 gas transmission and storage ("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. (The Utility expects to file an application to begin the next GT&S rate case in September 2013.) A substantial portion of the authorized revenue requirements, primarily those costs allocated to core customers, continue to be assured of recovery through balancing account mechanisms and/or fixed reservation charges. The Utility's ability to recover the remaining revenue requirements continues to depend on throughput volumes, gas prices, and the extent to which non-core customers and other shippers contract for firm transmission services. This volumetric cost recovery risk associated with each function (backbone transmission, local transmission, and storage) is summarized below.

Backbone Transmission. The backbone transmission revenue requirement is recovered through a combination of firm two-part rates (consisting of fixed monthly reservation charges and volumetric usage charges) and as-available one-part rates (consisting only of volumetric usage charges). The mix of firm and as-available backbone services provided by the Utility continually changes. As a result, the Utility's recovery of its backbone transmission costs is subject to volumetric and price risk to the extent that backbone capacity is sold on an as-available basis. Core procurement entities (including core customers served by the Utility) are the primary long-term subscribers to backbone capacity. Core customers are allocated approximately 38% of the total backbone capacity on the Utility's system. Core customers pay approximately 69% of the costs of the backbone capacity that is allocated to them through fixed reservation charges.

Local Transmission. The local transmission revenue requirement is allocated approximately 66% to core customers and 34% to non-core customers. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk.

Storage. The storage revenue requirement is allocated approximately 51% to core customers, 37% to non-core storage service, and 12% to pipeline load balancing service. The Utility recovers the portion allocated to core customers through a balancing account, but the Utility's recovery of the portion allocated to non-core customers is subject to volumetric and price risk. The revenue requirement for pipeline load balancing service is recovered in backbone transmission rates and is subject to the same cost recovery risks described above for backbone transmission.

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 sets the natural gas procurement rate for core customers monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core customers, through its retail gas rates. (The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered through electricity balancing accounts.)

The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under the Core Procurement Incentive Mechanism (“CPIM”). Under the CPIM, the Utility’s natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers’ rates. One-half of the costs above 102% of the benchmark are recoverable in customers’ rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility’s cost of natural gas that is less than 99% of the benchmark. The Utility retains the remaining amount of savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

In January 2010, the CPUC approved a joint settlement agreement among the Utility, the CPUC’s Division of Ratepayer Advocates, and The Utility Reform Network to incorporate a portion of hedging costs for core customers into the Utility’s CPIM beginning November 1, 2010. The settlement agreement has an initial term of seven years, through October 2017, which can be extended by agreement of the parties. As a result, the settlement agreement permits the Utility to develop and implement a sustained core hedging program. (For more information, see Note 10: Derivatives, of the Notes to the Consolidated Financial Statements in the 2012 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 2012, the Utility made significant capital investments in 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 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 also substantially completed the installation of an advanced metering infrastructure throughout its service territory in 2012. As of December 31, 2012, the Utility has installed approximately 8.9 million advanced electric and gas meters. As permitted by CPUC rules, customers may choose not to have an advanced meter installed. The new infrastructure uses SmartMeterTM 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'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. In March 2012, the Utility began 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. When an electrical outage occurs, these switches detect a short circuit, block power flow to the affected area, communicate with a central computer, and then quickly reroute power around the problem to keep as many customers powered as possible. 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 2012 represented by each major electricity resource.

Total 2012 Actual Electricity Delivered – 76,205 GWh:

	Percent of Bundled Retail Sales			
Owned Generation Facilities				
Nuclear	23.3	%		
Small Hydroelectric	1.2	%		
Large Hydroelectric	9.7	%		
Fossil fuel-fired	8.3	%		
Solar	0.2	%		
Total			42.7	%
Qualifying Facilities (1)				
Renewable	4.4	%		
Non-Renewable	9.8	%		
Total			14.2	%
Irrigation Districts and Water Agencies				
Small Hydroelectric	0.3	%		
Large Hydroelectric	3.5	%		
Total			3.8	%
Other Third-Party Purchase Agreements				
Renewable	12.9	%		
Large Hydroelectric	0.4	%		
Non-Renewable	11.5	%		
Total			24.8	%
Others, Net (2)			14.5	%
Total			100	%

(1) Electric utilities are required under federal law to purchase energy and capacity from independent power producers with generation facilities (20 MW or less) that meet the definition of a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978. QFs primarily include co-generation facilities that produce combined heat and power and renewable generation facilities. For more information about the power purchase agreements that the Utility has entered into with QFs, see "QF Power Purchase Agreements," below.

(2) This amount is mainly comprised of net CAISO open market purchases, offset by transmission and distribution related system losses.

Owned Generation Facilities

At December 31, 2012, 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	106	2,683
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal:		109	3,895
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:		10	102
Total		136	7,640

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. For the twelve months period ended December 31, 2012, the Utility’s Diablo Canyon power plant achieved an average overall capacity factor of approximately 90%. 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 2012 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 15: Commitments and Contingencies — Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2012 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 43.6 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2013	2014	2015	2016	2017
Unit 1					

Refueling	-	February	September	-	April
Duration (days)	-	40	40	-	30
Startup	-	March	November	-	May
Unit 2					
Refueling	February	September	-	May	-
Duration (days)	52	40	-	35	-
Startup	March	November	-	June	-

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 109 generating units at 68 powerhouses, including the Helms pumped storage facility. Most of the Utility's hydroelectric generation units are classified as "large" hydro facilities, as their unit capacity exceeds 30 MW. The Helms pumped storage facility consists of three motor/generator units. During 2011, the Utility began inspections of all three units following reports of a significant failure of a similarly designed pumped storage generation unit in Austria that was apparently caused by cracks in the generator rotor poles due to metal fatigue. The Utility completed inspections and repairs on each of the three units and returned them to service in 2012.

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 1,137 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 880 MW of the 1,137 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 3,002 MW of hydroelectric power will expire between 2013 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. On December 20, 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 that would be acquired by the Utility no sooner than January 1, 2016.

Photovoltaic Facilities. In April 2010, the CPUC approved the Utility's five-year program for the development of up to 250 MW of solar photovoltaic ("PV") facilities to be owned and operated by the Utility, along with entering into power purchase agreements for an additional 250 MW of PV facilities to be developed by third parties. Under the PV program, Utility-owned PV facilities with an aggregate of 100 MW are operational, and an additional 50 MW are under construction and expected to become operational in 2013. The 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), and the Giffen solar station (10 MW). All of these facilities are located in Fresno County. The PV facilities under construction are the Gates solar station (20 MW), the West Gates solar station (10 MW) and the Guernsey solar station (20 MW). The Gates and West Gates solar stations are located in Fresno County; the Guernsey solar station is located in Kings County.

In December 2012, the Utility sought CPUC approval to terminate the PV program early. If approved, the Utility will not pursue the development of the remaining 100 MW of Utility-owned PV facilities over the remaining two years of the program, but instead will procure this capacity through the CPUC's Renewable Auction Mechanism ("RAM") process. Additionally, the Utility proposed to solicit the remaining 152 MW of capacity to be provided under power purchase agreements through the RAM process rather than through the PV program.

Generation Resources from Third Parties

QF Power Purchase Agreements. Under the Public Utility Regulatory Policies Act ("PURPA") of 1978 electric utilities are required to purchase energy and capacity from independent power producers with generation facilities that meet the statutory definition of a qualifying facility ("QF"). In June 2011, the FERC approved the California investor-owned utilities' joint application to terminate their obligation under PURPA to purchase QF energy and capacity from facilities exceeding 20 MW. QFs primarily include co-generation facilities that produce combined heat and power and renewable generation facilities. As of December 31, 2012, the Utility had power purchase agreements with 180 operating QFs for approximately 3,000 MW of capacity. The majority of this capacity is from cogeneration facilities and the remainder is from renewable generation facilities. Agreements for approximately 2,700 MW expire at various dates between 2013 and 2028. QF power purchase agreements for approximately 300 MW have no specific expiration dates and will terminate only when the owner of the QF exercises its termination option. No single QF accounted for more than 5% of the Utility's 2012 electricity deliveries.

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 2013 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 15: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

Renewable Generation Resources

Renewable generation resources include bioenergy such as biogas and biomass, small hydroelectric, wind, solar, and geothermal energy. California's Renewables Portfolio Standard ("RPS") program gradually increases the amount of renewable energy that load-serving entities, such as the Utility, must deliver to their customers from an average of at least 20% of their total retail sales in the years 2011-2013 to 33% of their total retail sales in 2021 and thereafter. For more information regarding the new RPS program, see the section of MD&A entitled "Environmental Matters – Renewable Energy Resources" in the 2012 Annual Report, which information is incorporated herein by reference.

During 2012, 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 only small hydroelectric generation resources (30 MW or less) can qualify as a renewable resource for purposes of meeting the RPS mandate. 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 2012 renewable deliveries are stated in the table below.

Type	GWh	% of Bundled Load
Biopower	3,373	4.4%
Geothermal	3,803	5.0%
Wind	4,338	5.7%
Small Hydroelectric	1,812	2.4%
Solar	1,171	1.5%
Total	14,497	19.0%

For more information regarding the Utility's renewable energy contracts, see Note 15: Commitments and Contingencies — Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

Electricity Transmission

At December 31, 2012, the Utility owned approximately 18,100 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 60,800 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.

During 2012, the Utility upgraded several critical substations and re-conductored some transmission lines to improve maintenance and operating flexibility, reliability and safety, including the installation or replacement of 9 transmission substation banks. 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.

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 601 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 2012, the Utility replaced more than 130,000 feet of underground cable, primarily in San Francisco and Oakland, replaced 98,000 feet of overhead wire, and installed or replaced 39 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 2013.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2008 to 2012 for electricity sold or delivered, including the classification of revenues by type of service.

	2012	2011	2010	2009	2008
Customers (average for the year)	5,214,170	5,188,638	5,155,724	5,137,240	5,129,427
Deliveries (in GWh) (1)	86,113	81,255	79,634	72,385	74,783
Revenues (in millions):					
Residential	$ 4,953	$ 4,778	$ 4,795	$ 4,759	$ 4,656
Commercial	4,735	4,732	4,823	4,538	4,413
Industrial	1,408	1,379	1,424	1,392	1,400
Agricultural	901	692	736	770	727
Public street and highway lighting	79	77	79	74	75

Other	(11)	94	(1,178)	(1,700)	(863)
Subtotal	12,065	11,752	10,679	9,833	10,408
Regulatory balancing accounts	(51)	(151)	(35)	424	330
Total electricity operating revenues	$12,014	$11,601	$ 10,644	$ 10,257	$ 10,738
Other Data:					
Average annual residential usage (kWh)	5,961	6,799	6,843	6,953	7,007
Average billed revenues (per kWh):					
Residential	$ 0.1594	$ 0.1548	$ 0.1560	$ 0.1524	$ 0.1480
Commercial	0.1449	0.1441	0.1468	0.1377	0.1296
Industrial	0.917	0.951	0.988	0.940	0.867
Agricultural	0.1458	0.1475	0.1451	0.1327	0.1300
Net plant investment per customer	$ 4,919	$ 5,045	$ 4,728	$ 4,336	$ 3,994

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

Natural Gas Utility Operations

During 2012, the Utility has taken many immediate and longer-term steps to improve the safety and reliability of its natural gas transmission system, 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 ("PSEP"), approved by the CPUC in December 2012, to meet the new, industry-wide safety standards for gas transmission systems. (See the information within MD&A under the heading "Natural Gas Matters" in the 2012 Annual Report, which information is incorporated herein by reference.)

In 2012, as part of the PSEP pipeline modernization program, the Utility confirmed the strength of 202 miles of transmission pipeline through hydrostatic pressure tests or records verification, installed 46 automated or remote-controlled valves, replaced 40 miles of transmission pipeline, and retrofitted 78 miles of transmission pipeline to accommodate in-line inspection tools. Since work on the program began in 2011, the Utility has also collected and digitized more than 3.5 million pipeline records, which includes validating the Maximum Allowable Operating Pressure ("MAOP") for more than 89 percent of its gas transmission system (and 100 percent of the 2,088 miles of the Utility's transmission pipelines in populated areas).

The Utility is also improving operations by utilizing modern tools and technologies. In 2012, the Utility began demonstrating a new car-mounted natural gas leak detection device, which is much more sensitive than traditional instruments. The Utility also began using an advanced hand-held leak-detection instrument that uses infrared technology to pinpoint methane gas without false alarms from other gases. This technology can detect and grade leaks at the same time. In addition, the Utility improved its supervisory controls and data acquisition system ("SCADA") to better detect pipeline leaks and breaks and improved its integrity management program, including incorporating new analysis tools to identify and assess risks to pipeline integrity.

For the distribution system, the Utility has implemented a new distribution integrity management program designed to enhance operations and improve the overall safety of the gas distribution system. In 2012, the Utility replaced 23 miles of Aldyl-A plastic pipeline and identified another 150 miles to be replaced over the next two years. It also updated the geographic information system with information on more than 5,500 miles of Aldyl-A pipeline, including additional pipeline and service attribute information. The Utility also completed additional distribution leak surveys in 2012, in addition to complying with regular distribution leak survey requirements.

Many of these improvement efforts satisfy recommendations made to the Utility by the NTSB and the CPUC in 2010 and 2011. In the first half of 2012, the Utility was able to officially close out four of the twelve NTSB recommendations. In January 2013, the Utility requested closure on three more recommendations. The Utility continues to make significant progress on the remaining longer-term recommendations, and the NTSB stated in September 2012 that the Utility's progress was acceptable.

In December 2012, the CPUC accepted the gas safety plans submitted by each gas corporation in California, including the Utility, to describe each gas corporation's programs, plans, and initiatives, to increase the safety and reliability of their natural gas operations. The plans were submitted in compliance with California Senate Bill 705, enacted in October 2011, which requires each gas corporation subject to CPUC jurisdiction to develop and implement a plan for the safe and reliable operation of its gas pipeline system. The new law required the CPUC to review the plans and accept, modify, or reject each plan by December 31, 2012. The CPUC has ordered the Utility, as well as the other gas corporations, to submit modifications to their plans by June 2013 and to continually review, revise and update their plans as required by emerging issues, industry practices, and state and federal regulators.

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, 2012, the Utility's natural gas system consisted of approximately 42,400 miles of distribution pipelines, approximately 6,400 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 has incurred significant environmental liabilities related to some of its compressor stations. See "Environmental Matters" below.) The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems. The Utility's 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. The Utility's Line 400/401 interconnects at the California-Oregon border with the pipeline systems owned by Gas Transmission Northwest Corporation ("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 2012, core customers represented more than 99% of the Utility's total natural gas customers and 36% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total natural gas customers and 64% 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, over 96% of core customers, representing over 83% 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.

The Utility has regulatory balancing accounts for core customers designed to ensure that the Utility's results of operations over the long term are not affected by weather variations, conservation, energy efficiency measures, or changes in their consumption levels. The Utility's results of operations can be affected, however, by non-core consumption levels because there are fewer regulatory balancing accounts related to non-core customers. Approximately 97% of the Utility's natural gas distribution base revenues are recovered from core customers and the remainder from 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 2012, the Utility purchased approximately 247,792 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 10% of the total natural gas volume the Utility purchased during 2012.

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, the largest firm shipper on GTN's pipeline, has two firm transportation agreements with GTN for these services. In addition, the Utility 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 this region to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona.

Natural Gas Deliveries

The total volume of natural gas delivered to on-system customers during 2012 was approximately 945 MMDth. The following table shows the percentage of the Utility's total 2012 natural gas deliveries represented by each of the Utility's major customer classes.

Residential Customers	20%
Transport-only Customers (non-core)	75%
Commercial Customers	5%

The California Gas Report is prepared by the California electric and natural gas utilities to present an outlook for natural gas requirements and supplies for California over a long-term planning horizon. It is prepared in even-numbered years followed by a supplemental report in odd-numbered years. The 2012 California Gas Report forecasts average annual growth in the Utility's natural gas deliveries (for core customers and non-core transportation) of approximately 0.3% for the years 2010 through 2030. The natural gas requirements forecast is subject to many uncertainties, and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, price, and the number and location of electricity generation facilities.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2008 through 2012 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service.

	2012	2011	2010	2009	2008
Customers (average for the year)	4,353,278	4,327,407	4,295,741	4,271,007	4,269,165
Gas purchased (MMcf)	247,792	279,157	270,228	264,314	260,315
Average price of natural gas purchased	$ 2.45	$ 3.69	$ 4.07	$ 3.57	$ 7.51
Bundled gas sales (MMcf):					
Residential	185,376	201,109	195,195	195,217	198,699
Commercial	47,341	52,230	53,921	57,550	63,934
Total	232,717	253,339	249,116	252,767	262,633
Revenues (in millions):					
Bundled gas sales:					
Residential	$ 1,852	$ 2,089	$ 1,991	$ 1,953	$ 2,574
Commercial	383	464	474	496	792
Regulatory balancing accounts	221	295	305	289	221
Other	66	102	49	55	(30)
Bundled gas revenues	2,522	2,950	2,819	2,793	3,557
Transportation service only revenue	499	400	377	349	333
Operating revenues	$ 3,021	$ 3,350	$ 3,196	$ 3,142	$ 3,890
Selected Statistics:					
Average annual residential usage (Mcf)	45	49	48	48	49
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 9.99	$ 10.39	$ 10.20	$ 10.00	$ 12.95
Commercial	8.09	8.89	8.79	8.62	12.38
Net plant investment per customer	$ 1,696	$ 1,721	$ 1,637	$ 1,557	$ 1,344

Public Purpose and Customer Programs

California law has historically required the CPUC to authorize certain levels of funding for programs related to energy efficiency, research and development, and renewable energy resources through the collection of an electric public goods charge. The legislation authorizing the public goods charge expired on January 1, 2012. The CPUC has ordered the Utility to continue to collect in electric rates the amounts that were previously funded through the public goods charge for energy efficiency and established an energy program investment charge to support ongoing energy efficiency and research and development. Gas public interest research continues to be funded through the gas public purpose program surcharge. California law requires the CPUC to authorize funding for the California Solar Initiative and other self-generation programs, as discussed under "Self-Generation Incentive Program and California Solar Initiative," below. Additionally, the CPUC has authorized funding for energy savings assistance and demand response programs. For 2012, the Utility collected authorized revenue requirements of $688 million from electric customers and $169 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 a new 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 awarded the Utility $21 million for the successful implementation of the Utility's 2010 energy efficiency programs. The CPUC decision also established the process that is expected to apply to incentive claims for program years 2011 and 2012. After the CPUC completes its audit of the utilities' 2011 program expenditures, the utilities must file their incentive claims in the third quarter of 2013 for approval by the CPUC in the fourth quarter of 2013. Similarly, 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.

It is uncertain what form of incentive ratemaking the CPUC will establish and what amount, if any, the Utility will be authorized to earn for future energy efficiency programs.

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. Due to the timing of the decision, the CPUC authorized the Utility to recover both 2012 and 2013 program costs through customer rates collected in 2013.

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. In December 2011, the CPUC approved continuing 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 California Solar Initiative 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.

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 ("CARE") 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 2012, the amount of this subsidy was approximately $851 million. The CPUC also authorized the Utility to recover approximately $45 million in administrative costs relating to the CARE subsidy through 2014.

Environmental Matters

The Utility is subject to a number of 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 following:

- the discharge of pollutants into the air, water, and soil;
- the transportation, handling, storage and disposal of spent nuclear fuel;
- the identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting, remediation and emergency response in connection with hazardous and radioactive substances;
- the reporting and reduction of carbon dioxide (“CO2”) and other GHG emissions; 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 disposed.

The Utility’s estimated costs to comply with environmental laws and regulations are based on current estimates and assumptions that are subject to change. In addition, the Utility is likely to incur costs as it develops and implements strategies to mitigate the impact of its operations on the environment, including climate change and its foreseeable impact on the Utility’s future operations. 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 under “Recovery of Environmental Remediation Costs” below.

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, sulfur dioxide (“SO2”), nitrogen oxide (“NOx”) and particulate matter.

Federal Regulation. At the federal level, the U.S. Environmental Protection Agency (“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.

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 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 two-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. Each year 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 on the secondary market for trading GHG allowances. The CARB's first quarterly auction was held on November 14, 2012. Emitters (also known as covered entities) are required to obtain and surrender allowances equal to the amount of their GHGs emissions within a particular compliance period. Emitters may also meet up to 8% of their compliance obligation through the purchase of "offset credits" which represent GHG emissions abatement achieved in sectors that are not subject to the cap. For more information about the cap-and trade program, see the section of MD&A entitled "Environmental Matters" in the 2012 Annual Report, which information is incorporated herein by reference.

Increasing use of renewable energy supplies also is expected to help reduce GHG emissions in California. In April 2011, the California Governor signed legislation that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy delivered to their customers to at least 33% of the total amount of electricity retail sales by 2020. (See "Electricity Resources" above.) In December 2011, the CPUC approved various regulations to implement the new law, including the establishment of renewable energy targets for each compliance period. (For more information, see "Renewable Generation Resources" above.)

Climate Change Mitigation and Adaptation Strategies. During 2012, 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, safety-related pipeline hydrotesting, as well as normal pipeline maintenance, releases the GHG methane to the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression. In addition, the Utility continues to replace a substantial portion of its older cast iron and steel gas mains with new pipe, which reduces leakage.

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 2011 are the most recent data available. Since 2009, the Utility has complied with AB 32's annual GHG emissions reporting requirements, reporting combustion emissions from its electric generation facilities and natural gas compressor stations to the CARB. (For information about the sources of electric generation that the Utility delivered to customers in 2012, see "Electric Utility Operations– Electricity Resources" above.) Consistent with Utility practice since 2002, the Utility also voluntarily reported its 2011 GHG emissions to The Climate Registry ("TCR"), a non-profit organization that has a reporting and measurement standard applicable to most industry sectors across North America. Reporting to TCR enables the Utility to publicly report GHG emissions not covered by mandatory reporting requirements. The Utility's third-party verified voluntary GHG inventory for 2011 totaled more than 50 million metric tonnes of CO_2-equivalent (“CO_2-e”), which includes approximately 33 million metric tonnes CO_2-e from customer natural gas use.

Beginning with its 2010 emissions, the Utility also reported 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.

2011 Emissions Reported to the California Air Resources Board

For its 2011 emissions, the Utility began reporting the GHG emissions from natural gas supplied to customers and the fugitive emissions from its natural gas distribution system and compressor stations. 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)	2,025,543
Natural Gas Compressor Stations (2)	258,446
Distribution Fugitive Natural Gas Emissions	224,298
Customer Natural Gas Use (3)	39,049,732
Total	41,558,019

(1) Includes nitrous oxide (“N_2O”) and methane (“CH_4”) 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 CO_2-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 gas local distribution companies. This figure does not represent the Utility’s compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities as calculated by the CARB.

Benchmarking GHG Emissions for Delivered Electricity

The Utility’s third-party-verified CO_2 emissions rate associated with the electricity delivered to customers in 2011 was 393 pounds of CO_2 per MWh. The Utility’s 2011 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)	393

(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 2011. The Utility's fossil fuel-fired generation comprised approximately 6% of the Utility's delivered electricity in 2011.

	2011	2010
Total NOx Emissions (tons)	144	904
NOx Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.06	0.49
All Plants	0.008	0.06
Total SO2 Emissions (tons)	12	42
SO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	0.005	0.023
All Plants	0.0007	0.003
Total CO2 Emissions (metric tons)	2,024,206	1,545,892
CO2 Emissions Rates (pounds/MWh)		
Fossil Fuel-Fired Plants	875	943
All Plants	126	106
Other Emissions Statistics		
Sulfur Hexafluoride ("SF6") Emissions		
Total SF6 Emissions (metric tons CO2-equivalent)	70,052	69,066
SF6 Emissions Leak Rate	1.7%	1.8%

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Water Quality

Section 316(b) of the federal Clean Water Act requires that 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. On April 20, 2011, the EPA published draft regulations that propose specific reductions for impingement (which occurs when larger organisms are caught on water filter screens) and provide a case-by-case site specific assessment to establish compliance requirements for entrainment (which occurs when organisms are drawn through the cooling water system). The proposed site specific assessment allows for the consideration of a variety of factors including social costs and benefits, energy reliability, land availability, and non-water quality adverse impacts. The draft regulations were subject to public comment. In June 2012, the EPA issued a Notice of Data Availability proposing changes to the draft regulations which, if adopted, would provide more flexibility in complying with some of the requirements. The EPA is required to issue final regulations by July 2013.

On May 4, 2010, the California Water Resources Control Board ("California Water Board") adopted a policy on once-through cooling. The policy, effective October 1, 2010, generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities by at least 85%. However, with respect to the state's nuclear power generation facilities, the policy allows other compliance measures to be taken if the costs to install cooling towers are "wholly out of proportion" to the costs considered by the California Water Board in developing its policy. The policy also allows other compliance measures to be taken if the installation of cooling towers would be "wholly unreasonable" after considering non-cost factors such as engineering and permitting constraints and adverse environmental impacts. The Utility believes that the costs to install cooling towers at Diablo Canyon, which could be as much as $4.5 billion, will meet the "wholly out of proportion" test. The Utility also believes that the installation of cooling towers at Diablo Canyon would be "wholly unreasonable." The policy also established a nuclear review committee to evaluate the feasibility and cost of alternative technologies for nuclear plants. The committee's consultant, Bechtel, must complete an assessment for the California Water Board's review by October 2013. Upon review of the feasibility assessment, if the California Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. 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, may need to procure substitute power, and may incur a material charge. 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 ("RCRA") and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("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 (“DTSC”), 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 (“MGP”) 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 centers, 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 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 Polices,” and Note 15: Commitments and Contingencies–Environmental Remediation Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 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 DTSC 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. Of these sites owned or operated by the Utility, 40 sites have been or are in the process of being investigated and/or remediated, and the Utility is developing a strategy to investigate and remediate the last site. The Utility spent approximately $51 million in 2012 on these sites.

Third-Party Owned Disposal Sites

Under environmental laws, such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of waste from the Utility's facilities, or to pay for associated clean-up costs or natural resource damages. The Utility is currently aware of two such sites where investigation or clean-up activities are currently underway. At the Geothermal Incorporated site in Lake County, California, the Utility substantially completed closure of the disposal facility, which was abandoned by its operator. The Utility was the major responsible party and led the remediation effort on behalf of the responsible parties. For the Casmalia disposal facility near Santa Maria, California, the Utility and several parties that sent waste to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and remediation measures.

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 15: Commitments and Contingencies–Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference.

Recovery of Environmental Remediation Costs

The CPUC has authorized the Utility to recover most of its environmental remediation costs through various ratemaking mechanisms, subject to exclusions for certain sites, such as the Hinkley natural gas compressor site, and subject to limitations for certain liabilities such as amounts associated with fossil fuel-fired generation facilities formerly owned by the Utility. For more information, see Note 15: Commitments and Contingencies–Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 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. For more information, see Note 15: Commitments and Contingencies–Environmental Remediation Contingencies of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which information is incorporated herein by reference. 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 Triennal Proceeding in Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in the 2012 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 2012 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 March and September 2012, the Utility entered into 10-year facility lease agreements for 250,000 and 145,000 square feet of office space, respectively, in San Ramon, California. The Utility also recently entered into a lease agreement for a new 12,000 square foot data center located near Sacramento, California. In total, the Utility occupies 10.8 million square feet of real property, including 8.6 million square feet that the Utility owns. Of the 10.8 million square feet of occupied real property, approximately 1.7 million square feet represent the Utility's corporate headquarters located in several Utility-owned buildings in San Francisco, California.

The Utility currently owns approximately 167,000 acres of land, including approximately 140,000 acres of watershed lands. As part of the settlement agreement entered into by PG&E Corporation and the Utility to resolve the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code, the Utility agreed to protect its watershed lands with conservation easements or equivalent protections, and/or donate up to approximately 75,000 acres of its watershed lands to public entities or qualified non-profit conservation organizations. (The Utility will not donate watershed lands that contain the Utility's or a joint licensee's hydroelectric generation facilities or is otherwise used for utility operations, but this land may be encumbered with conservation easements.) The Utility formed a non-profit organization, the Pacific Forest Watershed Lands Stewardship Council ("Council") to oversee the development and implementation of a Land Conservation Plan ("LCP") that will articulate the long-term management objectives for the watershed lands. The Council is governed by an 18-member board of directors, one of whom was appointed by the Utility. The other members represent a range of diverse interests, including the CPUC, California environmental agencies, organizations representing underserved and minority constituencies, agricultural and business interests, and public officials. The Council's goal is to implement the transactions contemplated in the LCP over the next few years, subject to obtaining any required permits and approvals from the FERC, the CPUC, and other governmental agencies.

PG&E Corporation also leases approximately 82,000 square feet of office space from a third party in San Francisco, California, of which 40,000 square feet will expire in 2014 and the remaining in 2022.

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 15: Commitments and Contingencies–Legal and Regulatory Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 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 Regional Water Quality Control Board (“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.

In addition, the California Water Board’s policy on once-through cooling and regulations that are expected to be issued by the EPA in July 2013 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

At December 31, 2012, approximately 140 lawsuits involving third-party claims for personal injury and property damage, including two class action lawsuits, had been filed against PG&E Corporation and the Utility in connection with the San Bruno accident on behalf of approximately 450 plaintiffs. The lawsuits seek compensation for personal injury and property damage, and other relief, including punitive damages. These cases have been coordinated and assigned to one judge in the San Mateo County Superior Court. The trial of the first group of remaining cases began on January 2, 2013 with pretrial motions and hearings. On January 14, 2013, the court vacated the trial and all pending hearings due to the significant number of cases that have been settled outside of court. The court has urged the parties to settle the remaining cases. As of February 8, 2013, the Utility has entered into settlement agreements to resolve the claims of approximately 140 plaintiffs. It is uncertain whether or when the Utility will be able to resolve the remaining claims through settlement.

Additionally, in October 2010, a purported shareholder derivative lawsuit was filed following the San Bruno accident to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims, relating to the Utility's natural gas business. The case has been coordinated with the other cases in the San Mateo County Superior Court. The judge has ordered that proceedings in the derivative lawsuit be delayed until further order of the court. On February 7, 2013, another purported shareholder derivative lawsuit was filed in U.S. District Court for the Northern District of California to seek recovery on behalf of PG&E Corporation for alleged breaches of fiduciary duty by officers and directors, among other claims.

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. To state their claims, the plaintiffs cited the January 2012 investigative report from the CPUC's Safety and Enforcement Division ("SED") that alleged, from 1996 to 2010, the Utility spent less on capital expenditures and operations and maintenance expense for its natural gas transmission operations than it recovered in rates, by $95 million and $39 million, respectively. The SED recommended that the Utility should use such amounts to fund future gas transmission expenditures and operations. Plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of Section 17200 of the California Business and Professions Code ("Section 17200") and claim that this violation also constitutes a violation of California Public Utilities Code Section 2106 ("Section 2106"), which provides a private right of action for violations of the California constitution or state laws by public utilities. Plaintiffs seek restitution and disgorgement under Section 17200 and compensatory and punitive damages under Section 2106. PG&E Corporation and the Utility contest the allegations. In January 2013, PG&E Corporation and the Utility requested that the court dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. In the alternative, PG&E Corporation and the Utility requested that the court stay the proceeding until the CPUC investigations described above are concluded. The court has set a hearing on the motion for April 26, 2013.

For additional information, see the discussion within MD&A under the heading, "Natural Gas Matters" and in Note 15: Commitments and Contingencies of the Notes to the Consolidated Financial Statements contained in the 2012 Annual Report, which discussions are incorporated herein by reference.

Pending CPUC Investigations and Potential Enforcement Matters

The CPUC is conducting three investigations pertaining to the Utility's natural gas operations 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. In 2012, the SED issued investigative reports in each of these investigations alleging that the Utility committed numerous violations of applicable laws and regulations and recommending the CPUC impose penalties on the Utility. Evidentiary hearings were held in each of these investigations. The CPUC administrative law judges ("ALJs") who oversee the investigations have adopted a revised procedural schedule, including the dates by which the parties' briefs must be submitted. The ALJs have also permitted the other parties (the City of San Bruno, The Utility Reform Network, and the City and County of San Francisco) to separately address in their opening briefs their allegations against the Utility, if any, in addition to the allegations made by the SED.

The ALJs have ordered the SED and other parties to file single coordinated briefs to address potential monetary penalties and remedies (which could include remedial operational or policy measures) for all three investigations by April 26, 2013. After briefing has been completed, the ALJs will issue one or more presiding officer's decisions listing the violations determined to have been committed, the amount of penalties, and any required remedial actions. Based on the revised procedural schedule, one or more presiding officer's decisions will be issued by July 23, 2013. The decisions would become the final decisions of the CPUC thirty days after issuance unless the Utility or another party filed an appeal, or a CPUC commissioner requested review of the decision, within such time.

California gas corporations are required to provide notice to the CPUC of any self-identified or self-corrected violations of certain state and federal regulations related to the safety of natural gas facilities and utilities' natural gas operating practices. The CPUC has authorized the SED to issue citations and impose penalties based on self-reported violations. In April 2012, the CPUC affirmed a $17 million penalty that had been imposed by the SED based on the Utility's self-report that it failed to conduct periodic leak surveys because it had not included 16 gas distribution maps in its leak survey schedule. (The Utility has paid the penalty and completed all of the missed leak surveys.) As of December 31, 2012, the Utility has submitted 34 self-reports with the CPUC, plus additional follow-up reports. The SED has not yet taken formal action with respect to the Utility's other self-reports. The SED may issue additional citations and impose penalties on the Utility associated with these or future reports that the Utility may file.

In addition, in July 2012, the Utility reported to the CPUC that it had discovered that its access to some pipelines has been limited by vegetation overgrowth or building structures that encroach upon some of the Utility's gas transmission pipeline rights-of-way. The Utility is undertaking a system-wide effort to identify and remove encroachments from its pipeline rights-of-way over a multi-year period. PG&E Corporation and the Utility are uncertain how this matter will affect the investigative proceedings related to natural gas operations, or whether additional proceedings or investigations will be commenced by the CPUC that could result in regulatory orders or the imposition of penalties on the Utility.

The CPUC can impose significant penalties for violations of applicable laws, rules, and orders. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this discretion in determining penalties. The CPUC's delegation of enforcement authority to the SED allows the SED to use these factors in exercising discretion to determine the number of violations, but the SED is required to impose the maximum statutory penalty for each separate violation that the SED finds.

For more information, see discussions within MD&A under the heading, "Natural Gas Matters," and Note 15: Commitments and Contingencies–Legal and Regulatory Contingencies, of the Notes to the Consolidated Financial Statements in the 2012 Annual Report, which discussions are incorporated herein by reference

Criminal Investigation

On June 9, 2011, the Utility was notified that representatives from the U.S. Department of Justice, the California Attorney General's Office, and the San Mateo County District Attorney's Office are conducting an investigation of the San Bruno accident. These representatives have indicated that the Utility is a target of the investigation. The Utility is cooperating with the investigation. PG&E Corporation and the Utility are uncertain whether any criminal charges will be brought against either company or any of their current or former employees. PG&E Corporation and the Utility are unable to estimate the amount (or range of amounts) of reasonably possible losses associated with any civil or criminal penalties that could be imposed on the Utility. See the discussions within MD&A under the heading "Natural Gas Matters – Criminal Investigation," and in Note 15: Commitments and Contingencies of the Notes to the Consolidated Financial Statements in the 2012 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 Securities and Exchange Act of 1934 ("Exchange Act") at February 1, 2013 were as follows.

Name	Age	Position
Anthony F. Earley, Jr.	63	Chairman of the Board, Chief Executive Officer, and President
Kent M. Harvey	54	Senior Vice President and Chief Financial Officer
Christopher P. Johns	52	President, Pacific Gas and Electric Company
Hyun Park	51	Senior Vice President and General Counsel
Greg S. Pruett	55	Senior Vice President, Corporate Affairs
John R. Simon	48	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 1, 2013, 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	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
Kent M. Harvey	Senior Vice President and Chief Financial Officer	August 1, 2009 to present
	Senior Vice President, Financial Services, Pacific Gas and Electric Company	August 1, 2009 to present
	Senior Vice President and Chief Risk and Audit Officer	October 1, 2005 to July 31, 2009
Christopher P. Johns	President, Pacific Gas and Electric Company	August 1, 2009 to present
	Senior Vice President and Chief Financial Officer	May 1, 2009 to July 31, 2009
	Senior Vice President, Financial Services, Pacific Gas and Electric Company	May 1, 2009 to July 31, 2009
	Senior Vice President, Chief Financial Officer, and Treasurer	October 4, 2005 to April 30, 2009
	Senior Vice President and Treasurer, Pacific Gas and Electric Company	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	November 1, 2009 to present
	Senior Vice President, Corporate Affairs, Pacific Gas and Electric Company	November 1, 2009 to present

	Senior Vice President, Corporate Relations	November 1, 2007 to October 31, 2009
	Senior Vice President, Corporate Relations, Pacific Gas and Electric Company	March 1, 2009 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, Pacific Gas and Electric Company	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 1, 2013 were as follows:

Name	Age	Position
Anthony F. Earley, Jr.	63	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation
Christopher P. Johns	52	President
Nickolas Stavropoulos	54	Executive Vice President, Gas Operations
Geisha J. Williams	51	Executive Vice President, Electric Operations
Karen A. Austin	51	Senior Vice President and Chief Information Officer
Desmond A. Bell	50	Senior Vice President, Safety and Shared Services
Thomas E. Bottorff	59	Senior Vice President, Regulatory Affairs
Helen A. Burt	56	Senior Vice President and Chief Customer Officer
John T. Conway	55	Senior Vice President, Energy Supply
Edward D. Halpin	51	Senior Vice President and Chief Nuclear Officer
Kent M. Harvey	54	Senior Vice President, Financial Services
Gregory K. Kiraly	48	Senior Vice President, Electric Distribution Operations
Hyun Park	51	Senior Vice President and General Counsel, PG&E Corporation
Greg S. Pruett	55	Senior Vice President, Corporate Affairs
John R. Simon	48	Senior Vice President, Human Resources
Jesus Soto, Jr.	45	Senior Vice President, Gas Transmission Operations
Fong Wan	51	Senior Vice President, Energy Procurement
Dinyar B. Mistry	50	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 1, 2013, 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	January 1, 2012 to present
	Senior Vice President, Shared Services and Chief Procurement Officer	October 1, 2008 to December 31, 2011
	Vice President, Shared Services and Chief Procurement Officer	March 1, 2008 to September 30, 2008
	Vice President and Chief of Staff	March 19, 2007 to February 29, 2008
Thomas E. Bottorff	Senior Vice President, Regulatory Affairs	September 1, 2012 to present
	Senior Vice President, Regulatory Relations	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	March 1, 2012 to present
	Senior Vice President, Energy Supply and Chief Nuclear Officer	April 1, 2009 to February 29, 2012
	Senior Vice President, Generation and Chief Nuclear Officer	October 1, 2008 to March 31, 2009
	Senior Vice President and Chief Nuclear Officer	March 1, 2008 to September 30, 2008
	Site Vice President, Diablo Canyon Power Plant	May 29, 2007 to February 29, 2008
Edward D. Halpin	Senior Vice President and Chief Nuclear Officer	April 2, 2012 to present
	President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company	December 2009 to March 2012
	Chief Nuclear Officer, South Texas Project Nuclear Operating Company	October 2008 to November 2009
	Site Vice President, South Texas Project Nuclear Operating Company	June 2006 to September 2008
Kent M. Harvey	Senior Vice President, Financial Services	August 1, 2009 to present
	Senior Vice President and Chief Financial Officer, PG&E Corporation	August 1, 2009 to present
	Senior Vice President and Chief Risk and Audit Officer, PG&E Corporation	October 1, 2005 to July 31, 2009
Gregory K. Kiraly	Senior Vice President, Electric Distribution Operations	September 18, 2012 to present
	Vice President, Electric Distribution Operations	October 1, 2011 to September 17, 2012
	Vice President, SmartMeter Operations	August 23, 2010 to September 30, 2011
	Vice President, Electric Maintenance and Construction	January 1, 2010 to August 22, 2010
	Vice President, Transmission Substations, Maintenance and Construction	January 1, 2009 to December 31, 2009
	Vice President, Maintenance and Construction	April 14, 2008 to December 31, 2008
	Vice President, Distribution Systems Operations, Energy Delivery, Commonwealth Edison Company	June 2007 to April 2008
Hyun Park	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
Greg S. Pruett	Senior Vice President, Corporate Affairs	November 1, 2009 to present November 1, 2009 to present

	Senior Vice President, Corporate Affairs, PG&E Corporation	
	Senior Vice President, Corporate Relations	March 1, 2009 to October 31, 2009
	Senior Vice President, Corporate Relations, PG&E Corporation	November 1, 2007 to October 31, 2009
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to present
Jesus Soto, Jr.	Senior Vice President, Gas Transmission Operations	May 29, 2012 to present
	Vice President, Operations Services, El Paso Pipeline Group	May 2007 to May 2012
Fong Wan	Senior Vice President, Energy Procurement	October 1, 2008 to present
	Vice President, Energy Procurement	January 9, 2006 to September 30, 2008
Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller	October 1, 2011 to present
	Vice President and Controller, PG&E Corporation	March 8, 2010 to present
	Vice President and Controller	March 8, 2010 to September 30, 2011
	Vice President and Chief Risk and Audit Officer	September 16, 2009 to March 7, 2010
	Vice President and Chief Risk and Audit Officer, PG&E Corporation	August 1, 2009 to March 7, 2010
	Vice President, Internal Auditing/Compliance and Ethics, PG&E Corporation	January 1, 2009 to July 31, 2009
	Vice President, Regulation and Rates	September 20, 2007 to December 31, 2008

PART II

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

As of February 11, 2013, there were 67,982 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 2012 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 6: 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 2012 Annual Report, which information is incorporated herein by reference.

Sales of Unregistered Equity Securities

During the quarter ended December 31, 2012, PG&E Corporation made equity contributions totaling $170 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 2012.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
October 1 through October 31, 2012	-	-	-	$ -
November 1 through November 30, 2012	-	-	-	-
December 1 through December 31, 2012	406(1)	$39.71	-	-
Total	406	$39.71	-	$ -

(1) Shares of PG&E Corporation common stock tendered to pay stock option exercise price.

During the quarter ended December 31, 2012, 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 2012 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" in the 2012 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 10: Derivatives and Note 11: Fair Value Measurements of the Notes to the Consolidated Financial Statements in the 2012 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 2012 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 2012 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, 2012, 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, 2012 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 2012 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.

Item 9B. Other Information

2013 PG&E Corporation Short-Term Incentive Plan

On February 20, 2013, the Compensation Committee of the PG&E Corporation Board of Directors ("Committee") approved the PG&E Corporation 2013 Short-Term Incentive Plan ("STIP") under which officers and employees of PG&E Corporation and the Utility may receive cash awards based on the extent to which specified performance targets are met in each of three areas: safety (both public and employee), customer (which includes operational reliability and the efficient completion of pipeline safety work), and corporate financial performance. The resulting STIP scores for each of these measures will have the following weightings: safety (40%), customer (35%), and corporate financial performance (25%). The Committee also approved the specific performance targets for each of these STIP components.

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 2013 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 2013 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 2012 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2013 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 and Composition Audit Committees" and "Corporate Governance Board and Director Independence Committee Membership Requirements" and "Corporate Governance – Committee Membership" in the Joint Proxy Statement relating to the 2013 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 - 2012," "Grants of Plan-Based Awards in 2012," "Outstanding Equity Awards at Fiscal Year End - 2012," "Option Exercises and Stock Vested During 2012," "Pension Benefits – 2012," "Non-Qualified Deferred Compensation – 2012," "Potential Payment Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2012 Director Compensation" in the Joint Proxy Statement relating to the 2013 Annual

Meetings of Shareholders, which information is hereby 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 “Security Ownership of Management” and “Share Ownership Information - Principal Shareholders” in the Joint Proxy Statement relating to the 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2012 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	5,758,820	(1)	$30.05	4,548,119	(2)
Equity compensation plans not approved by shareholders	-		-	-	
Total equity compensation plans	5,758,820	(1)	$30.05	4,548,119	(2)

(1) Includes 45,597 phantom stock units, 2,101,484 restricted stock units and 3,088,896 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 6: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2012 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 PG&E Corporation Long-Term Incentive Program ("LTIP") and the PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP") as of December 31, 2012. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock, 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 6: Common Stock and Share-Based Compensation of the Notes to the Consolidated Financial Statements in the 2012 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 "Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company –Board and Director Independence” in the Joint Proxy Statement relating to the 2013 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 2013 Annual Meetings of Shareholders, which information is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are contained in the 2012 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2012 and 2011 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011, and 2010 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2012, 2011, and 2010 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2012, 2011, and 2010 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, 2012 and 2011 and for the Years Ended December 31, 2012, 2011, and 2010.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2012, 2011, and 2010.

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)

Exhibit Number	Exhibit Description
3.3	Bylaws of PG&E Corporation amended 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 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 20, 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 3)
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)

Exhibit Number	Exhibit Description
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	Fifteenth Supplemental Indenture dated as of November 22, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 20, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 22, 2011 (File No. 1-2348), Exhibit 4.1)
4.15	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)
4.16	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)
4.17	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)
4.18	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)
4.19	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	Credit Agreement, dated May 31, 2011, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and

	East West Bank (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.2	Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank

Exhibit Number	Exhibit Description
10.3	Credit Agreement, dated May 31, 2011, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (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 10.2)
10.4	Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank
10.5	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)
10.6	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)
10.7	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)
10.8*	Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation dated May 12, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.3)
10.9*	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)
10.10*	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)
10.11*	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)
10.12*	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)
10.13*	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)
10.14*	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 10.4)

Exhibit Number	Exhibit Description
10.15*	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)
10.16*	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)
10.17*	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)
10.18*	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007
10.19*	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)
10.20*	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)
10.21*	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)
10.22*	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)
10.23*	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)
10.24*	PG&E Corporation 2005 Supplemental Retirement Savings Plan effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009 and as further amended with respect to investment options effective as of July 13, 2009 and as of August 1, 2011) (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.11)
10.25*	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)
10.26*	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)
10.27*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013

10.28*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2012 (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)
10.29*	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)

Exhibit Number	Exhibit Description
10.30*	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)
10.31*	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013
10.32*	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, effective January 1, 2013
10.33*	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)
10.34*	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)
10.35 *	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)
10.36*	Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013
10.37*	Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013
10.38*	Resolution of the PG&E Corporation Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010 (File No. 1-12609), Exhibit 10.31)
10.39*	Resolution of the Pacific Gas and Electric Company Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2010 (File No. 1-12348), Exhibit 10.32)
10.40*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013
10.41 *	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective June 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.10)
10.42*	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)
10.43*	Form of Restricted Stock 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)
10.44*	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)
10.45*	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)
10.46*	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)
10.47*	Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.39)

Exhibit Number	Exhibit Description
10.48*	Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.45)
10.49*	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)
10.50*	Form of Restricted Stock Unit Agreement for 2011 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, 2011 (File No. 1-12609), Exhibit 10.9)
10.51*	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)
10.52*	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)
10.53*	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)
10.54*	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)
10.55*	Form of Performance Share 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 10.3)
10.56*	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)
10.57*	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)
10.58*	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)
10.59*	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)
10.60*	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)
10.61*	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)
10.62*	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)
10.63*	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)
10.64*	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)

Exhibit Number	Exhibit Description
10.65*	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)
10.66 *	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)
10.67*	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 2012 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "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, 2012 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION (Registrant)	PACIFIC GAS AND ELECTRIC COMPANY (Registrant)
By: ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr. Chairman of the Board, Chief Executive Officer, and President	By: CHRISTOPHER P. JOHNS Christopher P. Johns President
Date: February 21, 2013	Date: February 21, 2013

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		
ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr.	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation)	February 21, 2013
CHRISTOPHER P. JOHNS Christopher P. Johns	President (Pacific Gas and Electric Company)	February 21, 2013
B. Principal Financial Officers		
KENT M. HARVEY Kent M. Harvey	Senior Vice President and Chief Financial Officer (PG&E Corporation)	February 21, 2013
DINYAR B. MISTRY Dinyar B. Mistry	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 21, 2013

C. Principal
Accounting Officer

DINYAR B. MISTRY Dinyar B. Mistry	Vice President and Controller (PG&E Corporation) Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	February 21, 2013

D. Directors

David R. Andrews	Director	February 21, 2013
*LEWIS CHEW Lewis Chew	Director	February 21, 2013
*C. LEE COX C. Lee Cox	Director	February 21, 2013

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*ANTHONY F. EARLEY, JR. Anthony F. Earley, Jr.	Director	February 21, 2013
*FRED J. FOWLER Fred J. Fowler	Director	February 21, 2013
*MARYELLEN C. HERRINGER Maryellen C. Herringer	Director	February 21, 2013
*CHRISTOPHER P. JOHNS Christopher P. Johns	Director (Pacific Gas and Electric Company only)	February 21, 2013
*ROGER H. KIMMEL Roger H. Kimmel	Director	February 21, 2013
*RICHARD A. MESERVE Richard A. Meserve	Director	February 21, 2013
*FORREST E. MILLER Forrest E. Miller	Director	February 21, 2013
*ROSENDO G. PARRA Rosendo G. Parra	Director	February 21, 2013
*BARBARA L. RAMBO Barbara L. Rambo	Director	February 21, 2013
*BARRY LAWSON WILLIAMS Barry Lawson Williams	Director	February 21, 2013

*By: HYUN PARK
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, 2012 and 2011, and for each of the three years in the period ended December 31, 2012, and the Company's and the Utility’s internal control over financial reporting as of December 31, 2012, and have issued our reports thereon dated February 21, 2013 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to several investigations and enforcement matters 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 2012 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 21, 2013

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, 2012	2011	2010
Administrative service revenue	$ 43	$ 44	$ 53
Operating expenses	(41)	(44)	(55)
Interest income	1	1	1
Interest expense	(22)	(22)	(35)
Other income (expense)	(39)	(17)	4
Equity in earnings of subsidiaries	817	852	1,105
Income before income taxes	759	814	1,073
Income tax benefit	57	30	26
Net income	$ 816	$ 844	$ 1,099
Other Comprehensive Income			
Pension and other postretirement benefit plans (net of income tax of $72, $9, $25 in 2012, 2011, and 2010, respectively)	108	(11)	(42)
Other (net of income tax of $3 in 2012)	4	-	-
Total other comprehensive income (loss)	112	(11)	(42)
Comprehensive Income	$ 928	$ 833	$ 1,057
Weighted average common shares outstanding, basic	424	401	382
Weighted average common shares outstanding, diluted	425	402	392
Net earnings per common share, basic	$ 1.92	$ 2.10	$ 2.86
Net earnings per common share, diluted	$ 1.92	$ 2.10	$ 2.82

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS. In addition, during 2010, PG&E Corporation applied the "if-converted" method to reflect the impact of the Convertible Subordinated Notes to the extent it was dilutive when compared to basic EPS.

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

	Balance at December 31, 2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 207	$ 209
Advances to affiliates	26	18
Income taxes receivable	33	8
Deferred income taxes	-	4
Total current assets	266	239
Noncurrent Assets		
Equipment	1	14
Accumulated depreciation	(1)	(14)
Net equipment	-	-
Investments in subsidiaries	13,387	12,378
Other investments	102	94
Income taxes receivable	5	2
Deferred income taxes	178	143
Other	1	2
Total noncurrent assets	13,673	12,619
Total Assets	$ 13,939	$ 12,858
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 120	$ -
Accounts payable – other	48	21
Income taxes payable	-	57
Other	221	208
Total current liabilities	389	286
Noncurrent Liabilities		
Long-term debt	349	349
Other	127	122
Total noncurrent liabilities	476	471
Common Shareholders' Equity		
Common stock	8,428	7,602
Reinvested earnings	4,747	4,712
Accumulated other comprehensive loss	(101)	(213)
Total common shareholders' equity	13,074	12,101
Total Liabilities and Shareholders' Equity	$ 13,939	$ 12,858

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

	Year Ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities:			
Net income	$ 816	$ 844	$ 1,099
Adjustments to reconcile net income to net cash provided by operating activities:			
Stock-based compensation amortization	51	36	38
Equity in earnings of subsidiaries	(817)	(852)	(1,105)
Deferred income taxes and tax credits, net	(31)	(26)	19
Noncurrent income taxes receivable/payable	(6)	(47)	34
Current income taxes receivable/payable	(82)	49	(1)
Other	20	(80)	(50)
Net cash provided by (used in) operating activities	(49)	(76)	34
Cash Flows From Investing Activities:			
Investment in subsidiaries	(1,023)	(759)	(347)
Dividends received from subsidiaries (1)	716	716	716
Proceeds from tax equity investments	228	129	7
Other	-	-	(4)
Net cash provided by (used in) investing activities	(79)	86	372
Cash Flows From Financing Activities:			
Borrowings under revolving credit facilities	120	150	90
Repayments under revolving credit facilities	-	(150)	(90)
Common stock issued	751	662	303
Common stock dividends paid (2)	(746)	(704)	(662)
Other	1	1	-
Net cash provided by (used in) financing activities	126	(41)	(359)
Net change in cash and cash equivalents	(2)	(31)	47
Cash and cash equivalents at January 1	209	240	193
Cash and cash equivalents at December 31	$ 207	$ 209	$ 240
Supplemental disclosures of cash flow information			
Cash received (paid) for:			
Interest, net of amounts capitalized	$ (20)	$ (20)	$ (20)
Income taxes, net	(60)	8	36
Supplemental disclosures of noncash investing and financing activities			
Noncash common stock issuances	$ 22	$ 24	$ 265
	196	188	183

Common stock dividends declared but not yet paid

(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, 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.

On January 15, 2010, PG&E Corporation paid a quarterly common stock dividend of $0.42 per share. On April 15, July 15, and October 15, 2010, 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, 2012, 2011, and 2010
(in millions)

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions (2)	Balance at End of Period
Valuation and qualifying accounts deducted from assets:					
2012:					
Allowance for uncollectible accounts(1)	$ 81	$ 66	$ -	$ 60	$ 87
2011:					
Allowance for uncollectible accounts(1)	$ 81	$ 60	$ -	$ 60	$ 81
2010:					
Allowance for uncollectible accounts(1)	$ 68	$ 56	$ -	$ 43	$ 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, 2012, 2011, and 2010
(in millions)

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (2)	Balance at End of Period
Valuation and qualifying accounts deducted from assets:					
2012:					
Allowance for uncollectible accounts(1)	$ 81	$ 66	$ -	$ 60	$ 87
2011:					
Allowance for uncollectible accounts(1)	$ 81	$ 60	$ -	$ 60	$ 81
2010:					
Allowance for uncollectible accounts(1)	$ 68	$ 56	$ -	$ 43	$ 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 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 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 20, 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 3)
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)

Exhibit Number	Exhibit Description
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	Fifteenth Supplemental Indenture dated as of November 22, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 20, 2012 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 22, 2011 (File No. 1-2348), Exhibit 4.1)
4.15	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)
4.16	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)
4.17	

	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)
4.18	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)

Exhibit Number	Exhibit Description
4.19	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	Credit Agreement, dated May 31, 2011, among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.1)
10.2	Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) PG&E Corporation, as borrower, (2) Bank of America, N.A. as administrative agent and a lender, (3) Citibank, N.A., and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank
10.3	Credit Agreement, dated May 31, 2011, among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank (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 10.2)
10.4	Amendment No. 1, dated as of December 24, 2012, to the May 31, 2011 Credit Agreement among (1) Pacific Gas and Electric Company, as borrower, (2) Citibank, N.A., as administrative agent and lender, (3) JPMorgan Chase Bank, N.A., and Bank of America, N.A., as co-syndication agents and lenders, and (4) The Royal Bank of Scotland plc and Wells Fargo Bank, National Association as co-documentation agents and lenders, and (5) the following other lenders: Barclays Bank PLC, BNP Paribas, Deutsche Bank AG, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., UBS Loan Finance LLC, The Bank of New York Mellon, Banco Bilbao Vizcaya Argentaria S.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank National Association, Union Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and East West Bank

10.5	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)
10.6	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)
10.7	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)
10.8*	Restricted Stock Unit Agreement between C. Lee Cox and PG&E Corporation dated May 12, 2011 (incorporated by reference to PG&E Corporation’s Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.3)

Exhibit Number	Exhibit Description
10.9*	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)
10.10*	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)
10.11*	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)
10.12*	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)
10.13*	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)
10.14*	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 10.4)
10.15*	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)
10.16*	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)
10.17*	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)
10.18*	Letter regarding Compensation Arrangement between PG&E Corporation and John R. Simon dated March 9, 2007
10.19*	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)
10.20*	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)
10.21*	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)
10.22*	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)
10.23*	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)
10.24*	PG&E Corporation 2005 Supplemental Retirement Savings Plan effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009 and as further amended with respect to investment options effective as of July 13, 2009 and as of August 1, 2011) (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.11)

Exhibit Number	Exhibit Description
10.25*	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)
10.26*	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)
10.27*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2013
10.28*	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2012 (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)
10.29*	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)
10.30*	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)
10.31*	PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013
10.32*	PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, effective January 1, 2013
10.33*	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)
10.34*	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)
10.35 *	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)
10.36*	Resolution of the PG&E Corporation Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013
10.37*	Resolution of the Pacific Gas and Electric Company Board of Directors dated September 19, 2012, adopting director compensation arrangement effective January 1, 2013
10.38*	Resolution of the PG&E Corporation Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2010

	(File No. 1-12609), Exhibit 10.31)
10.39*	Resolution of the Pacific Gas and Electric Company Board of Directors dated December 15, 2010, adopting director compensation arrangement effective January 1, 2011 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2010 (File No. 1-12348), Exhibit 10.32)
10.40*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013
10.41*	PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective June 15, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12609), Exhibit 10.10)
10.42*	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)

Exhibit Number	Exhibit Description
10.43*	Form of Restricted Stock 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)
10.44*	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)
10.45*	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)
10.46*	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)
10.47*	Form of Restricted Stock Agreement for 2007 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (reflecting amendments to the PG&E Corporation 2006 Long-Term Incentive Plan made on February 15, 2006) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006 (File No. 1-12609), Exhibit 10.39)
10.48*	Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.45)
10.49*	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)
10.50*	Form of Restricted Stock Unit Agreement for 2011 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, 2011 (File No. 1-12609), Exhibit 10.9)
10.51*	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)
10.52*	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)
10.53*	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)
10.54*	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)
10.55*	Form of Performance Share 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 10.3)
10.56*	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)
10.57*	

	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)
10.58*	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)

Exhibit Number	Exhibit Descrkiption
10.59*	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)
10.60*	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)
10.61*	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)
10.62*	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)
10.63*	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)
10.64*	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)
10.65*	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)
10.66 *	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)
10.67*	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 2012 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: “Selected Financial Data,” “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

Exhibit Number	Exhibit Description
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.