

PG&E CORP

FORM 10-K (Annual Report)

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2008

☐ 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



One Market, Spear Tower
Suite 2400
San Francisco, California 94105
(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 Alternext

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

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

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

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

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

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

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

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

PG&E Corporation ☒
Pacific Gas and Electric Company ☒

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

PG&E Corporation

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

Pacific Gas and Electric Company

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

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

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

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2008, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation Common Stock \$14,179 million
Pacific Gas and Electric Company Common Stock Wholly owned by PG&E Corporation

Common Stock outstanding as of February 20, 2009:

PG&E Corporation: 365,764,340 shares
Pacific Gas and Electric Company: 264,374,809 shares (wholly owned by PG&E Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

Designated portions of the combined 2008 Annual Report to Shareholders Part I (Items 1 and 1.A.), Part II (Items 5, 6, 7, 7A, 8 and 9A)

Designated portions of the Joint Proxy Statement relating to the 2009 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

PART I

Item 1. Business

General

Corporate Structure and Business

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company (“Utility”) a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. 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 served approximately 5.1 million electricity distribution customers and approximately 4.3 million natural gas distribution customers at December 31, 2008. The Utility had approximately \$40.5 billion of assets at December 31, 2008 and generated revenues of approximately \$14.6 billion in 2008. Its revenues are generated mainly through the sale and delivery of electricity and natural gas. The Utility is regulated primarily by the California Public Utilities Commission (“CPUC”), and the Federal Energy Regulatory Commission (“FERC”).

Corporate and Other Information

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive office of the Utility is located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000. PG&E Corporation and the Utility file 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, are available free of charge on both PG&E Corporation's website, www.pgecorp.com, and the Utility's website, www.pge.com. 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.

Employees

At December 31, 2008, PG&E Corporation and its subsidiaries had approximately 21,667 regular employees, including approximately 21,451 regular employees of the Utility. Of the Utility's regular employees, approximately 14,649 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”). One IBEW collective bargaining agreement expires on December 31, 2011 and the other IBEW collective bargaining agreement expires on December 31, 2010. The ESC collective bargaining agreement expires on December 31, 2009. The Utility and the ESC reached an agreement in January 2009 to extend the collective bargaining agreement until December 31, 2011, subject to ratification by members of the ESC. The SEIU collective bargaining agreement expires on July 31, 2009.

Cautionary Language Regarding Forward-Looking Statements

This combined Annual Report on Form 10-K, including the information incorporated by reference from the joint Annual Report to Shareholders for the year ended December 31, 2008 (“2008 Annual Report”), contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, estimated future cash flows, and the level of future equity or debt issuances, and are also identified by words such as “assume,” “expect,” “intend,” “plan,” “project,” “believe,” “estimate,” “target,” “predict,” “anticipate,” “aim,” “may,” “might,” “should,” “would,” “could,” “goal,” “potential” and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to manage capital expenditures and its operating and maintenance expenses within authorized levels;
 - the outcome of pending and future regulatory proceedings and whether the Utility is able to timely recover its costs through rates;
 - the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets including the ability of the Utility and its counterparties to post or return collateral;
 - the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards on the Utility's facilities and operations, its customers, and third parties on which the Utility relies;
 - the potential impacts of climate change on the Utility's electricity and natural gas businesses;
 - changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology, including the development of alternative energy sources, or other reasons;
 - operating performance of Diablo Canyon, the availability of nuclear fuel, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
 - whether the Utility can maintain the cost savings it has recognized from operating efficiencies it has achieved and identify and successfully implement additional sustainable cost-saving measures;
 - whether the Utility incurs substantial expense to improve the safety and reliability of its electric and natural gas systems;
 - whether the Utility achieves the CPUC's energy efficiency targets and recognizes any incentives the Utility may earn in a timely manner;
 - the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
 - the impact of changing wholesale electric or gas market rules, including new rules of the California Independent System Operator ("CAISO") to restructure the California wholesale electricity market;
 - how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility's holding company;
 - the extent to which PG&E Corporation or the Utility incurs costs and liabilities in connection with litigation that are not recoverable through rates, from insurance, or from other third parties;
 - the ability of PG&E Corporation, the Utility, and counterparties to access capital markets and other sources of credit in a timely manner on acceptable terms, especially given the recent deteriorating conditions in the economy and financial markets;
 - the impact of environmental laws and regulations and the costs of compliance and remediation;
 - the effect of municipalization, direct access, community choice aggregation, or other forms of bypass; and
 - the impact of changes in federal or state tax laws, policies, or regulations.
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PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

For more information about the significant risks that could affect PG&E Corporation and the Utility's future financial condition and results of operations, see the discussion under "Risk Factors" that appears near the end of the section entitled "[Management's Discussion and Analysis of Financial Condition and Results of Operations](#)" ("MD&A") in the 2008 Annual Report.

PG&E Corporation's Regulatory Environment

Federal Energy Regulation

As a public utility holding company, PG&E Corporation is subject to the requirements of the Energy Policy Act of 2005 ("EPAct"), which became effective on February 8, 2006. Among its key provisions, the EPAct repealed the Public Utility Holding Company Act of 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"). Under PUHCA 2005, public utility holding companies fall principally under the regulatory oversight of the FERC, an independent agency within the U.S. Department of Energy ("DOE"). PG&E Corporation and its subsidiaries are exempt from all requirements of PUHCA 2005 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.

State Energy Regulation

PG&E Corporation is not a public utility under California law. The CPUC has authorized the formation of public utility holding companies subject to various conditions related to finance, human resources, records and bookkeeping, and the transfer of customer information. The financial conditions provide that:

- the Utility cannot guarantee any obligations of PG&E Corporation without prior written consent from the CPUC;
- the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company;
- 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); and
- 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.

(As discussed below under "Item 3—Legal Proceedings," the California Attorney General and the City and County of San Francisco have alleged that PG&E Corporation and its directors, as well as the directors of the Utility, violated the CPUC's holding company conditions during the California 2000-2001 energy crisis. PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules and orders.)

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 rules also prohibit each utility from engaging in certain practices that would discriminate against energy service providers that compete with that utility's affiliates. In December 2006, the CPUC revised its rules to, among other changes:

- emphasize that the holding company may not aid or abet a utility's violation of the rules or act as a conduit to provide confidential utility information to an affiliate;
 - require prior CPUC approval before the utility can contract with an affiliate for resource procurement (*e.g.*, electricity or gas), except in blind transactions where the identity of the other party is not known until the transaction is consummated;
 - require certain key officers to provide annual certifications of compliance with the affiliate rules;
 - prohibit certain key officers from serving in the same position at both the utility and the holding company (unless otherwise permitted by the CPUC), or, in the alternative, prohibit the sharing of lobbying, regulatory relations and certain legal services (except for legal services necessary to the provision of permitted shared services);
 - require the utility to obtain a "nonconsolidation opinion" indicating that it would not be consolidated into a bankruptcy of its holding company; and
 - make the CPUC's Energy Division responsible for hiring independent auditors to conduct biennial audits to verify that the utility is in compliance with the affiliate rules.
-

The CPUC has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

The Utility's 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. In addition to enacting PUHCA 2005 to replace the Public Utility Holding Company Act of 1935, as discussed above, the EPAct significantly amended various federal energy laws applicable to electric and natural gas markets, including the Federal Power Act of 1935, the Natural Gas Act of 1938 and the Public Utility Regulatory Policies Act of 1978 ("PURPA").

This section and the "Rate-making Mechanisms" section below summarize some of the more significant laws, regulations and regulatory mechanisms 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 the Utility does not currently anticipate. For discussion of specific pending regulatory proceedings that are expected to affect the Utility see the section of MD&A entitled "Regulatory Matters" in the 2008 Annual Report.

Federal Energy Regulation

The FERC

The FERC regulates the transmission and wholesale sales of electricity in interstate commerce and the transmission and sale of natural gas for resale in interstate commerce. The FERC also regulates interconnections of transmission systems with other electric systems and generation facilities; tariffs and conditions of service of regional transmission organizations, including the CAISO; and the terms and rates of wholesale electricity sales. The EPAct granted the FERC significant new responsibilities to oversee the reliability of the nation's electricity transmission grid, 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 EPAct also expanded the FERC's authority to impose penalties 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 can impose penalties of up to \$1,000,000 per day per violation. The FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas.

Electric Reliability Standards; Development of Transmission Grid . As part of its directive to oversee the development of mandatory electric reliability standards to protect the national electric transmission system, the FERC certified the North American Electric Reliability Corp. ("NERC"), as the nation's Electric Reliability Organization under the EPAct of 2005. 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, will also perform a regular 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. Under FERC authority the WECC, NERC, and/or FERC may impose penalties up to \$1,000,000 per day per violation.

The FERC also has issued rules on electric transmission pricing reforms designed to promote needed investment in energy infrastructure, to reduce transmission congestion, and to require transmission organizations with organized electricity markets to make long-term firm transmission rights available to load-serving entities, so these entities can enter into long-term transmission service arrangements without being exposed to unhedged congestion cost risk. In addition, 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.

Prevention of Market Manipulation . The EPAct also gave the FERC broader authority to police and penalize the exercise of market power or behavior intended to manipulate prices paid in FERC-jurisdictional transactions. In January 2006, the FERC adopted rules to prohibit market manipulation, modeling its new rules on SEC Rule 10b-5, which prohibits fraud and manipulation in the purchase or sale of securities. Under the FERC's new regulations, it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas, electric energy, or transportation/transmission services subject to the jurisdiction of the FERC: (1) to use or employ any device, scheme or artifice to defraud, (2) to make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (3) to engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any person.

QF Regulation . Under PURPA, electric utilities were required to purchase energy and capacity from independent power producers that are qualifying cogeneration facilities (“QFs”). To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices and eligibility requirements. The EPAct significantly amended the purchase requirements of PURPA. As amended, Section 210(m) of PURPA authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA to purchase the electricity offered to it by a QF (under a new contract or obligation), if the FERC finds that the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers as to a particular QF or on a “service territory-wide basis.” The Utility plans to assess whether it will file a request with the FERC to terminate its obligations under PURPA to enter into new QF purchase obligations after the implementation of the new day ahead market structure provided for in the CAISO’s Market Redesign and Technology Update (“MRTU”) initiative which is further discussed below.

The NRC

The Nuclear Regulatory Commission (“NRC”) oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the 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, 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.

The NRC operating license for Diablo Canyon Unit 1 expires in November 2024 and the NRC operating license for Diablo Canyon Unit 2 expires in August 2025. Under the terms of these licenses, there must be sufficient storage capacity for the radioactive spent fuel produced by the Diablo Canyon plant. For a discussion of the Utility’s spent fuel storage project, see “Environmental Matters – Nuclear Fuel Disposal,” below.

State Energy Regulation

California Legislature

The Utility’s operations have been significantly affected by various statutes passed by the California Legislature, including:

- *Assembly Bill 1890*. Assembly Bill 1890, enacted in 1996, mandated the restructuring of the California electricity industry, commencing in 1998, which was intended to create a competitive market for electricity generation and give customers of the investor-owned utilities the ability to choose “direct access” by buying energy from a service provider other than the regulated utilities. (Subsequent legislation, described below, suspended direct access during the California energy crisis of 2000-2001.) Among other provisions, Assembly Bill 1890 also provided for the establishment of the CAISO, as a nonprofit public benefit corporation, to operate and control the state-wide electricity transmission grid and ensure efficient use and reliable operation of the transmission grid.
 - *Assembly Bill 1X*. Assembly Bill 1X was enacted during the California 2000-2001 energy crisis when the California investor-owned electric utilities were no longer able to buy electricity. Assembly Bill 1X authorized the California Department of Water Resources (“DWR”) beginning on February 1, 2001, to purchase electricity and sell that electricity directly to the investor-owned electric utilities’ retail customers. Assembly Bill 1X required the California investor-owned electric utilities to deliver electricity purchased by the DWR under the contracts and to act as the DWR’s billing and collection agent. To ensure that the DWR recovers its costs to procure electricity, Assembly Bill 1X required the CPUC to suspend the right of retail end-user customers to become direct access customers until the DWR no longer procures electricity pursuant to Assembly Bill 1X. The current DWR contracts terminate at various dates through 2015.
 - *Assembly Bill 57*. Assembly Bill 57, enacted in September 2002 and amended by Senate Bill 1976, required the California investor-owned utilities to resume purchasing power on January 1, 2003, required the CPUC to allocate electricity to be provided under the DWR contracts among the customers of the California investor-owned electric utilities, requires the utilities to file short- and long-term electricity resource procurement plans with the CPUC for approval, and authorizes the utilities to timely recover their reasonable wholesale procurement costs incurred under a CPUC-approved procurement plan through the establishment of new electricity procurement balancing accounts that reflect differences between recorded revenues and costs incurred under the approved procurement plans.
 - *Senate Bill 1078*. Senate Bill 1078, enacted in September 2002 (as amended by Senate Bill 107, enacted in September 2006 and effective on January 1, 2007) established the renewables portfolio standard (“RPS”) program, which requires each California retail seller of electricity, except municipal utilities, to increase its purchases of eligible renewable energy (such as biomass,
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- small hydroelectric, wind, solar and geothermal energy) by at least 1% of its retail sales, so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. An unexcused failure to satisfy the RPS targets may result in a penalty of five cents per kilowatt hour with an annual penalty cap of \$25 million. The California Legislature is considering proposals to increase the RPS mandate to at least 33% by 2020.
- *Assembly Bill 380.* Assembly Bill 380, enacted in September 2005, requires the CPUC, in consultation with the CAISO, to establish resource adequacy requirements for all load-serving entities, including the California investor-owned electric utilities but excluding local publicly owned electric utilities. Assembly Bill 380 requires each load-serving entity to maintain physical generating capacity adequate to meet its load requirements, including peak demand and planning and operating reserves, deliverable to locations and at times as may be necessary to provide reliable electric service.
- *Assembly Bill 32.* Assembly Bill 32, enacted in September 2006, requires the California Air Resources Board (“CARB”) to adopt regulations to limit statewide greenhouse gas emission, to 1990 levels by 2020, with certain limits beginning in 2012. (See “Environmental Matters” below for more information.)
- *Senate Bill 1368.* Senate Bill 1368, also enacted in September 2006, prohibits any load-serving entity, including investor-owned electric utilities, from entering into a long-term financial commitment for baseload generation (i.e., electricity generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60%) unless it complies with a greenhouse gas emission performance standard. (See “Environmental Matters” below for more information.)

The CPUC

The CPUC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity distribution, electricity generation, natural gas distribution, and natural gas transportation and storage services in California. 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, rate of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning and aspects of the siting of the electricity transmission system. 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 consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms.

PG&E Corporation and the Utility entered into a settlement agreement with the CPUC on December 19, 2003, to resolve the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code that had been pending in the U.S. Bankruptcy Court for the Northern District of California (“Bankruptcy Court”) since April 2001, referred to as the Chapter 11 Settlement Agreement. The nine-year Chapter 11 Settlement Agreement established certain regulatory assets and addressed various ratemaking matters to restore the Utility's financial health and enable it to emerge from Chapter 11. The terms of the Chapter 11 Settlement Agreement were incorporated into the Utility's plan of reorganization under Chapter 11, which became effective on April 12, 2004. The Bankruptcy Court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of the Chapter 11 Settlement Agreement, in addition to other matters. (For more information, see Note 15 of the Notes to the Consolidated Financial Statements included in the 2008 Annual Report.)

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 of 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 forecasting future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

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. 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 are some of the more significant examples. Some licenses and

permits may be revoked or modified by the granting agency if facts develop or events occur that differ significantly from the facts and projections assumed in granting the approval. Furthermore, discharge permits and other approvals and licenses are granted for a term 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 over 520 franchise agreements with various 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. Franchise fees are computed pursuant to statute under either the Broughton Act or the Franchise Act of 1937. In addition, charter cities can negotiate their fees. 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, including an agreement with a large charter city. The franchise agreements generally require that the Utility install and maintain the electric and gas facilities in compliance with regulations adopted by cities and counties in the exercise of their police powers relating to the use of the public streets. 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

Historically, energy utilities operated as regulated monopolies within service territories in which they were essentially the sole suppliers of natural gas and electricity services. These utilities owned and operated all of the businesses and facilities necessary to generate, transport and distribute energy. Services were priced on a combined, or bundled, basis with rates charged by the energy companies designed to include all the costs of providing these services. Under traditional cost-of-service regulation, the utilities undertook a continuing obligation to serve their customers, in return for which the utilities were authorized to charge regulated rates sufficient to recover their costs of service, including timely recovery of their operating expenses and a reasonable return on their invested capital. The objective of this regulatory policy was to provide universal access to safe and reliable utility services. Regulation was designed in part to take the place of competition and ensure that these services were provided at fair prices.

In recent years, energy utilities have faced intensifying pressures to unbundle, or price separately, those services that are no longer considered natural monopolies. The most significant of these services are the commodity components—the supply of electricity and natural gas. The driving forces behind these competitive pressures have been customers who believe that they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators responded to these forces by providing for more competition in the energy industry. Regulators and legislators, to varying degrees, have required utilities to unbundle rates in order to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

Competition in the Electricity Industry

Federal . At the federal level, many provisions of the EPAct support the development of competition in the wholesale electric market. The EPAct has directed the FERC to develop rules to encourage fair and efficient competitive markets by employing best practices in market rules and reducing barriers to trade between markets and among regions. The EPAct also gives the FERC 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.

Even before the passage of the EPAct, the FERC's policies supported the development of a competitive electricity generation industry. FERC Order 888, issued in 1996, established standard terms and conditions for parties seeking access to regulated utilities' transmission grids. Order 888 requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file an open access non-discriminatory transmission tariff (“OATT”) that contains minimum terms and conditions of non-discriminatory service. The FERC's subsequent Order 2000, issued in late 1999, established national standards for regional transmission organizations, and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electricity generation and retail electricity markets. On February 16, 2007, the FERC issued Order 890, which is designed to: (1) strengthen the form of the OATT adopted in Order 888 to ensure that tariffs achieve their original purpose of remedying undue discrimination; (2) provide greater specificity in the form of the OATT to reduce opportunities for undue discrimination and facilitate the FERC's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system.

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 transmission providers to favor their own generation, facilitate market entry for generation

competitors by streamlining and standardizing interconnection procedures, and encourage needed investment in generation and transmission. Under the rules and associated tariffs, a new generator is required to pay for the transmission system upgrades needed in order to interconnect the generator. The generator will be reimbursed over a five-year period after the power plant achieves commercial operation. The cost of the network upgrades is then recovered by the regulated transmission provider in its overall transmission rates.

State. At the state level, Assembly Bill 1890 mandated the restructuring of the California electricity industry commencing in 1998. Assembly Bill 1890 established a market framework 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 Power Exchange (“PX”). As a result of the California 2000-2001 energy crisis, 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 Chapter 11 proceeding, see Note 15 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.) The CAISO, which was established pursuant to AB 1890 to take control of the California investor-owned electric transmission facilities located in California, currently administers a real-time or “spot” wholesale market for the sale of electric energy. This market is used to allocate space on the transmission lines, maintain operating reserves, and match supply with demand in real time. The CAISO’s MRTU initiative is intended to restructure the California electricity market and to enhance power grid reliability, including the implementation of a new day-ahead market. The CAISO also will provide congestion revenue rights to allow market participants, including load-serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The MRTU tariffs will apply to all load-serving entities, including the investor-owned utilities, serving California consumers. The CAISO has delayed the start date of MRTU several times but is now targeting April 1, 2009. Also, in January 2008, the CPUC staff issued its recommendation to establish a statewide wholesale electric capacity market to replace the current resource adequacy program. Any changes the CPUC adopts would be subject to FERC approval.

Assembly Bill 1890 also permitted retail end-use customers to choose their energy service provider by becoming a direct access customer. To ensure that the DWR recovers its costs to procure electricity for the customers of the investor-owned electric utilities, Assembly Bill 1X required the CPUC to suspend the right of retail end-user customers to become direct access customers until the DWR no longer procures electricity on behalf of the customers of the California investor-owned electric utilities. The CPUC suspended direct access on September 20, 2001, but allowed existing direct access customers to continue being served by alternative energy service providers, rather than investor-owned electric utilities. The CPUC has assessed an additional charge on certain direct access customers to avoid a shift of costs from direct access customers to customers who receive bundled service. The CPUC is actively investigating how the DWR can terminate its obligations under the power contracts, by assignment or otherwise, to hasten the reinstatement of direct access.

In addition, the Utility’s customers may, under certain circumstances, obtain power from a “community choice aggregator” instead of from the Utility. California Assembly Bill 117, enacted in 2002, permits cities and counties to purchase and sell electricity for their local residents and businesses once they have registered as community choice aggregators. Under Assembly Bill 117, the Utility would continue to provide distribution, metering and billing services to the community choice aggregators’ customers and would be those customers’ provider of electricity of last resort. However, once registration has occurred, each community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The CPUC has adopted rules to implement community choice aggregation, including the imposition of a surcharge on retail end-users of the community choice aggregator to prevent a shifting of costs to customers of a utility who receive bundled services. Assembly Bill 117 also authorized the Utility to recover from each community choice aggregator any costs of implementing the program that are reasonably attributable to the community choice aggregator, and to recover from customers any costs of implementing the program not reasonably attributable to a community choice aggregator. No cities or counties are currently operating as community choice aggregators, but the San Joaquin Valley Power Authority has filed an implementation plan and stated that it may begin operating in 2009. In addition, the County of Marin and several cities in that county have voted to pursue community choice aggregation and have formed a joint powers agency to do so, but have not yet filed an implementation plan.

Competition in the Natural Gas Industry

FERC Order 636, issued in 1992, required interstate natural gas pipeline companies to divide their services into separate gas commodity sales, transportation and storage services. Under Order 636, interstate natural gas pipeline companies must provide transportation service whether or not the customer (often a local gas distribution company) buys the natural gas commodity from these companies. The Utility’s natural gas pipelines are located within the State of California and are exempt from the FERC’s rules and regulations applicable to interstate pipelines; the Utility’s pipeline operations are instead subject to the jurisdiction of the CPUC. The Utility’s gas transmission and storage system has operated under the CPUC-approved “Gas Accord” market structure since 1998. This market structure largely mimics the regulatory framework required by the FERC for interstate gas pipelines. The CPUC divides

the Utility's natural gas customers into two categories: "core" customers, which are primarily small commercial and residential customers, and "non-core" customers, which are primarily industrial, large commercial and electric generation customers. Under the Gas Accord structure, non-core customers have access to capacity rights for firm service, as well as interruptible (or "as-available") services. All services are offered on a nondiscriminatory basis to any creditworthy customer. The Gas Accord market structure has resulted in a robust wholesale gas commodity market at the Utility's "citygate," which refers to the interconnection between the big "backbone" gas transmission system and the smaller, downstream local transmission systems.

The Utility's first Gas Accord, a settlement agreement reached among the Utility and many interested parties, was approved by the CPUC in 1997, took effect on March 1, 1998, and was renewed, with slight modifications, for various successive periods. In September 2007, the CPUC approved the Gas Accord IV covering 2008 through 2010. The Gas Accord separated the Utility's natural gas transmission and storage rates from its distribution services and rates. The Gas Accord also changed the nature of the Utility's transmission and storage services by creating path-specific transmission services, firm and interruptible service offerings, standard and negotiated rate options, and a secondary market for trading of firm capacity rights. Additionally, the Gas Accord eliminated balancing account protection for some services, increasing the Utility's risk/reward potential.

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 natural gas relative to the total delivered cost of natural gas from the southwestern United States. The total delivered cost of natural gas includes, in addition to the commodity cost, transportation costs on all pipelines that are used to deliver the natural gas, which, in the Utility's case, includes the cost of transportation of the natural gas from Canada to the California border and the amount that the Utility charges for transportation from the border to southern California. In general, when the total cost of western Canadian natural gas 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.

PG&E Corporation, through its subsidiary, PG&E Strategic Capital, Inc., along with Fort Chicago Energy Partners, L.P. and Northwest Pipeline Corporation, have agreed to jointly pursue the development of a new 230-mile interstate gas transmission pipeline that would increase natural gas supplies for the entire West Coast region of the United States. The proposed Pacific Connector Gas Pipeline, together with the proposed Jordan Cove liquefied natural gas ("LNG") terminal in Coos Bay, Oregon, being developed by Fort Chicago Energy Partners, L.P., would open growing West Coast natural gas markets to diverse worldwide natural gas supply sources, providing additional alternatives to traditional Canadian, Southwest and Rocky Mountain supplies and increasing supply options and reliability. The proposed Pacific Connector Gas Pipeline would connect the proposed Jordan Cove LNG terminal to Northwest Pipeline Corporation's pipeline system in Oregon, and to the Utility's backbone gas transmission system near Malin, Oregon. Other potential interconnects include Tuscarora Gas Transmission Company's pipeline system, which serves northern Nevada. The proposed Pacific Connector Gas Pipeline would be capable of delivering 1 Bcf per day to the West Coast natural gas market, to customers in the Pacific Northwest through Northwest Pipeline Corporation's pipeline system, to the Utility's system for delivery to customers in California, and to customers in northern Nevada through Tuscarora Gas Transmission Company's pipeline system. It is expected that the FERC will issue a certificate authorizing construction and operation of the pipeline in 2009.

The development and construction of the Pacific Connector Gas Pipeline depends upon the construction of the proposed LNG terminal at Jordan Cove by Fort Chicago Energy Partners, L.P. PG&E Corporation cannot predict whether Fort Chicago Energy Partners, L.P. will be successful in completing the development and construction of its proposed LNG terminal. In addition, the development and construction of the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline are subject to obtaining required permits, regulatory approvals, and commitments under long-term capacity contracts. Assuming the required permits, authorizations, and long-term capacity commitments are timely received and that other conditions are timely satisfied, the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline could begin commercial operation in 2013.

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 determine the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers. The CPUC determines the Utility's revenue requirements associated with electricity and 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.

Regulatory balancing accounts are used to adjust the Utility’s revenue requirements. Sales balancing accounts track differences between the Utility’s recorded revenues and its authorized revenue requirements, due primarily to sales fluctuations. In general, electricity sales are higher in the summer months and natural gas sales are higher in the winter months. Cost balancing accounts track differences between the Utility’s incurred costs and its authorized revenue requirements, most importantly for energy commodity costs and volumes that can be affected by seasonal demand, weather, and other factors. Balances in all CPUC-authorized accounts are subject to review, verification audit, and adjustment, if necessary, by the CPUC.

To develop retail rates, the revenue requirements are allocated among customer classes (mainly residential, commercial, industrial and agricultural) and to various service components (mainly customer, demand, and energy). 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.

Through cost-of-service ratemaking, rates are developed to produce the revenue requirements, including the authorized return on rate base. The Utility may be unable to earn its authorized rate of return because the CPUC or the FERC excludes the Utility’s actual costs from the revenue requirements or because the Utility’s actual costs are higher than those reflected in the revenue requirements.

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 reliability standards or 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 basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC generally conducts a GRC every three years. The CPUC sets revenue requirement levels for a three-year rate period based on a forecast of costs for the first or “test” year. Typical interveners in the Utility’s GRC include the CPUC’s Division of Ratepayer Advocates and The Utility Reform Network. On March 15, 2007, the CPUC approved a multi-party settlement agreement to resolve the Utility’s 2007 GRC. The decision set the Utility’s electricity and natural gas distribution and electricity generation revenue requirements for a four-year period, from 2007 through 2010, rather than for a typical three-year period. Under the decision, the Utility’s next GRC will be effective January 1, 2011. The Utility intends to submit a draft of the 2011 GRC application and revenue requirement request to the CPUC in July or August 2009. For more information, see the section of MD&A entitled “Results of Operations” in the 2008 Annual Report.

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. The CPUC’s decision in the Utility’s 2007 GRC includes a provision for attrition adjustments made in 2008, and to be made in 2009 and 2010. For more information, see the section of MD&A entitled “Results of Operations” in the 2008 Annual Report.

Cost of Capital Proceedings

The CPUC generally conducts a proceeding to determine the Utility’s authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the relative weightings of common equity, preferred equity and debt in the Utility’s total authorized capital structure. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. In May 2008, the CPUC adopted a uniform three-year cost of capital mechanism to set the cost of capital for the Utility and the other two California investor-owned electric utilities. The utilities are required to file full cost of capital applications by April 20 of every third year, beginning on April 20, 2010.

The cost of capital mechanism uses an interest rate index (the 12-month October through September average of the Moody's Investors Service utility bond index) to trigger changes in the authorized cost of debt, preferred stock, and equity. In any year in which the 12-month October through September average for the index increases or decreases by more than 100 basis points ("deadband") from the benchmark, the cost of equity will be adjusted by one-half of the difference between the 12-month average and the benchmark. In addition, if the mechanism is triggered, the costs of long-term debt and preferred stock will be adjusted to reflect the actual August month-end embedded costs in that year and forecasted interest rates for variable long-term debt and any new long-term debt and preferred stock forecasted to be issued in the coming year. The 12-month October 2007 through September 2008 average of the Moody's Investors Service utility bond index did not trigger a change in the authorized cost of debt, preferred stock, or equity for 2009.

The Utility's current CPUC-authorized capital structure consists of 46% long-term debt, 2% preferred stock and 52% common equity. The Utility's current CPUC-authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base is 6.05% for long-term debt, 5.68% for preferred stock and 11.35% for common equity, resulting in an overall rate of return on rate base of 8.79%. This capital structure and authorized rate of return will be maintained through 2010, unless the automatic adjustment mechanism is triggered. The utilities may apply for an adjustment to either the cost of capital or the capital structure sooner based on extraordinary circumstances.

Although the FERC has authority to set the Utility's rate of return for its electricity transmission operations, the rate of return is often unspecified if the Utility's transmission rates are determined through a negotiated rate settlement.

Baseline Allowance

The CPUC sets and periodically revises a baseline allowance for the Utility's residential gas and electricity customers. A customer's baseline allowance is the amount of its monthly usage that is covered under the lowest possible natural gas or electric rate. Natural gas or electricity usage in excess of the baseline allowance is covered by higher rates that increase with usage.

Public Purpose and Other Programs

California law requires the CPUC to authorize certain levels of funding for electric and gas public purpose programs related to energy efficiency, low-income energy efficiency, research and development, and renewable energy resources. California law also requires the CPUC to authorize funding for the California Solar Initiative and other self-generation programs as discussed below. Additionally, the CPUC has authorized funding for demand response programs.

For 2008, the CPUC authorized the Utility to collect revenue requirements of approximately \$741.7 million of which approximately \$656.6 million is collected from electric customers to fund electric public purpose and other programs and approximately \$85.1 million is collected from gas customers to fund natural gas public purpose and other programs. The CPUC is responsible for authorizing the programs, funding levels and cost recovery mechanisms for the Utility's operation of these programs. The CEC administers both the electric and natural gas public interest research and development programs and the renewable energy program on a statewide basis. In 2008, the Utility transferred approximately \$79.5 million to the CEC for CEC-administered gas and electric programs. See the discussion below for a further description of these programs and authorized funding amounts.

- *Energy Efficiency Programs* . The Utility's energy efficiency programs are designed to encourage the manufacture, design, distribution and customer use of energy efficient appliances and other energy-using products. The CPUC authorized funding of \$403 million for 2008 gas and electric programs, including funding for the CEC-administered programs. The Utility intends to file an amended application on March 2, 2009 to seek CPUC approval and funding authorization of approximately \$1.8 billion for the Utility's 2009-2011 energy efficiency programs, an approximate increase of \$860 million over the 2006-2008 budget. On October 16, 2008, the CPUC authorized bridge funding for 2009 of \$394.9 million to allow the Utility to continue existing energy efficiency programs until the CPUC issues a final decision on the 2009-2011 application.

The CPUC has set certain goals for energy efficiency savings and has established an incentive ratemaking mechanism to encourage the California investor-owned utilities to promote energy efficiency and to meet the CPUC's goals over the 2006-2008 and 2009-2011 program cycles. To earn an award a utility must (1) achieve at least 85% of the CPUC's overall energy savings goal over the three-year program cycle and (2) achieve at least 80% of the CPUC's individual kWh, kW, and gas therm savings goals over the three-year program cycle. If the utility achieves between 85% and 99% of the CPUC's overall savings goal, 9% of the verified net benefits (*i.e.*, energy resource savings minus total energy efficiency program costs) will accrue to shareholders and 91% of the verified net benefits will accrue to customers. If the utility achieves 100% or more of the CPUC's overall savings goal, then 12% of the total verified net benefits will accrue to shareholders and 88% will accrue to customers. If the utility achieves less than 65% of any one of the individual metric savings goals (*i.e.*, kWh, kW, or gas therm), then the Utility must reimburse customers based on the greater of (1) 5 cents per

kWh, 45 cents per therm, and \$25 per kW for each kWh, therm, or kW unit below the 65% threshold, or (2) a dollar-for-dollar payback of negative net benefits, also known as a cost-effectiveness guarantee. The maximum award that the Utility could earn, and the maximum amount that the Utility could be required to reimburse customers over the 2006-2008 program cycle is \$180 million.

On January 29, 2009, the CPUC instituted a new proceeding to modify the existing incentive ratemaking mechanism, to adopt a new framework to review the utilities' 2008 energy efficiency performance and to conduct a final review of the utilities' performance over the 2006-2008 program period. The CPUC also plans to develop a long-term incentive mechanism for program periods beginning in 2009 and beyond. For more information, see the section of MD&A entitled "Regulatory Matters—Energy Efficiency Programs and Incentive Ratemaking" in the 2008 Annual Report.

- *Demand Response Programs.* Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. The 2008 authorized funding for Demand Response Programs was \$38 million. The CPUC has not yet approved the Utility's request for funding of approximately \$148 million for the Utility's 2009-2011 demand response programs. On December 18, 2008, the CPUC authorized bridge funding of \$41 million to continue certain demand response programs in 2009 until a final decision is issued on the Utility's request.

In addition, on February 14, 2008, the CPUC approved the Utility's multi-year air conditioning direct load control program and authorized funding of \$179 million through June 1, 2011 to implement this program. The 2008 authorized funding level was approximately \$37 million. Customers who enroll in this program will allow the Utility to remotely control the temperature settings of their central air conditioners to temporarily decrease their energy usage during local or system emergencies. The decision will allow the Utility to enroll approximately 397,000 air conditioning load control devices to achieve approximately 305 MW of load reduction capacity by June 2011.

- *Self-Generation Incentive Program and California Solar Initiative.* The Utility administers the self-generation incentive program ("SGIP") authorized by the CPUC to provide incentives to electricity customers who install certain types of clean or renewable distributed generation resources that meet all or a portion of their onsite energy usage. The CPUC approved a budget for the SGIP of approximately \$36 million in each of 2008 and 2009. In late 2006, the CPUC also established the California Solar Initiative ("CSI") to bring 1,940 MW of solar power on-line by 2017 in California and authorized the California investor-owned utilities to collect an additional \$2.2 billion over the 2007 through 2016 period from their customers to fund customer incentives for the installation of retail solar energy projects to serve onsite load to meet this goal. Of the total amount authorized, the Utility has been allocated \$946 million to fund customer incentives, research, development and demonstration activities (with an emphasis on the demonstration of solar and solar-related technologies), and administration expenses. The California Legislature modified the CSI program to include participation of the California municipal utilities. The current overall goal of the CSI is to install 3,000 MW (through both investor-owned electric utilities and electric municipal utilities) through 2017.
- *Low-Income Energy Efficiency Programs and California Alternate Rates for Energy.* The CPUC authorized the Utility to collect approximately \$86 million for these programs in 2008. The CPUC has authorized the Utility to collect approximately \$422 million to support the Utility's energy efficiency programs for low-income and fixed-income customers over 2009-2011. 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. The extent of the subsidy, during any given year, depends upon the number of customers participating in the program. In 2008, the amount of this subsidy was approximately \$526.6 million, including avoided customer surcharges. The CPUC also authorized the Utility to recover approximately \$28 million in administrative costs relating to the CARE subsidy over 2009-2011.

Rate Recovery of Costs of New Electricity Generation Resources

Overview

Each California investor-owned electric utility is responsible for procuring electricity to meet customer demand, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts (including DWR allocated contracts). To accomplish this, each utility must submit a long-term procurement plan covering a ten-year period to the CPUC for approval. Each long-term procurement plan must be designed to reduce greenhouse gas emissions and use the State of California's preferred loading order to meet 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). In December 2007, the CPUC approved the utilities' long-term procurement plans, covering the 2007-2016 period, subject to certain required modifications. California legislation, Assembly Bill 57, allows the utilities to recover the costs

incurred in compliance with their CPUC-approved procurement plans without further after-the-fact reasonableness review. Each utility may, if appropriate, conduct a competitive request for offers (“RFO”) within the parameters permitted in its approved plan to meet the utility’s projected need for electricity resources. Contracts that are entered into after the RFO process are submitted to the CPUC for approval, along with a request for the CPUC to authorize revenue requirements to recover the associated costs. The utilities conduct separate competitive solicitations to meet their renewable energy resource requirements. The utilities submit the renewable energy contracts after the conclusion of these solicitations to the CPUC for approval and authorization of the associated revenue requirements. For more information about the Utility’s approved long-term procurement plan covering 2007-2016, see “Electric Utility Operations — Electricity Resources-Future Long-Term Generation Resources” below.

The Utility recovers its electricity procurement costs and the fuel costs for the Utility’s own generation facilities (but excluding the costs of electricity allocated to the Utility’s customers under DWR contracts) through the Energy Resource Recovery Account (“ERRA”), a balancing account authorized by the CPUC in accordance with Assembly Bill 57. The ERRA tracks the difference between the authorized revenue requirement and actual costs incurred under the Utility’s authorized procurement plans and contracts. To determine the authorized revenue requirement recorded in the ERRA, each year the CPUC reviews the Utility’s forecasted costs under power purchase agreements and fuel costs. Although California legislation requiring the CPUC to adjust a utility’s retail electricity rates when the forecast aggregate over-collections or under-collections in the ERRA exceed 5% of a utility’s prior year electricity procurement revenues (excluding amounts collected for the DWR contracts) expired on January 1, 2006, the CPUC has extended this mandatory rate adjustment mechanism for the length of a utility’s resource commitment or 10 years, whichever is longer. The CPUC also performs compliance reviews of the procurement activities recorded in the ERRA to ensure that the Utility’s procurement activities are in compliance with its approved procurement plans. The Chapter 11 Settlement Agreement also provides that the Utility will recover its reasonable costs of providing utility service, including power purchase costs.

Costs Incurred Under New Power Purchase Agreements

The CPUC has approved several power purchase agreements that the Utility has entered into with third parties in accordance with the Utility’s CPUC-approved long-term procurement plan and to meet renewable energy 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 elect to recover any above-market costs through either: (1) the imposition of a non-bypassable charge imposed on bundled and departing customers only or (2) the allocation of the “net capacity costs” (i.e., contract price less energy revenues) to all “benefiting customers” in the utilities’ service territory, including existing direct access customers and community choice aggregation customers. (For information about the status of direct access and community choice aggregation, see the section above entitled “Competition in the Electricity Industry.”)

The non-bypassable charge can be imposed from the date of signing a power purchase agreement and last for 10 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 10 years on a case-by-case basis. If a utility elects to use the net capacity cost allocation method, the net capacity costs would be allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. Under this allocation mechanism, the energy rights to the contract are auctioned off to maximize the energy revenues and minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the Utility would retain the rights to the energy and would value it at market prices for the purposes of determining the net capacity costs to be allocated until the next periodic auction.

Costs of Utility-Owned Generation Resource Projects

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 CPUC-authorized revenue requirements to recover the initial capital costs for utility-owned generation projects are recovered through a balancing account, 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 the 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. For more information, see the section of MD&A entitled “Capital Expenditures – New Generation Facilities” in the 2008 Annual Report.

DWR Electricity and DWR Revenue Requirements

During the California 2000-2001 energy crisis, the DWR entered into long-term contracts to purchase electricity from third parties. The electricity provided under these contracts has been allocated to the electric customers of the three California investor-owned electric utilities. The DWR pays for its costs of purchasing electricity from a revenue requirement collected from these

customers through a rate component called the DWR "power charge." The rates that these customers pay also include a "bond charge" to pay a share of the DWR's revenue requirements to recover costs associated with the DWR's \$11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the implementation of the DWR's revenue requirement and to provide the DWR with funds to make its electricity purchases. The Utility acts as a billing and collection agent for the DWR for these amounts; however, amounts collected for the DWR and any adjustments are not included in the Utility's revenues.

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: charges under the Utility's transmission owner tariff and charges under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations in March 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, consistent with the federal filed rate doctrine, and are collected from retail electric customers receiving bundled service.

Transmission Owner Rate Cases

The primary FERC rate-making proceeding to determine the amount of revenue requirements 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, setting rates for a one-year period. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. For more information about the Utility's TO rate cases, see the section of MD&A entitled "Regulatory Matters — Electric Transmission Owner Rate Cases" in the 2008 Annual Report.

The Utility's transmission owner tariff includes two 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.

The other component consists of rates intended to reflect credits and charges from the CAISO. The CAISO credits the Utility for transmission revenues received by the CAISO. These revenues include:

- the proceeds received from the CAISO for wholesale wheeling service (*i.e.*, the transfer of electricity that is being sold in the wholesale market) that the CAISO provides to third parties using the Utility's transmission facilities, and
- revenues that the CAISO collects from transmission users to relieve congestion on the Utility's transmission line (either in the form of financial hedges, such as firm transmission rights relating to future deliveries of electricity, or in the form of a usage charge to manage congestion relating to real-time delivery of electricity).

These revenues are adjusted by the shortfall or surplus resulting from any cost differences between the amount the Utility is entitled to receive from certain wholesale customers under specific contracts and the amount the Utility is entitled to receive or be charged for scheduling services under the CAISO's rules and protocols.

The CAISO also charges the Utility for reliability service costs and imposes a transmission access charge for the Utility's use of the CAISO-controlled electric transmission grid in serving its customers. The CAISO's transmission access charge methodology, approved by the FERC in December 2004, provides for a transition over a 10-year period, from 2000-2009, to a uniform statewide high-voltage transmission rate. This rate is based on the revenue requirements associated with facilities operated at 200 kV and above of all transmission-owning entities that become participating transmission owners under the CAISO tariff. The transmission access charge methodology may result in a cost shift from transmission owners, whose costs for existing transmission facilities at 200 kV and above are higher than that embedded in the uniform transmission access charge rate, to transmission owners with lower embedded costs for existing high voltage transmission, such as the Utility. The Utility's obligation for this cost differential has been capped at \$32 million per year during the 10-year transition period.

Natural Gas

The Gas Accord

On September 20, 2007, the CPUC issued a final decision approving a multi-party settlement agreement, known as the Gas Accord IV, to establish the Utility's natural gas transmission and storage rates and associated revenue requirements from January 1,

2008 through December 31, 2010. The Gas Accord IV establishes a 2008 natural gas transmission and storage revenue requirement of \$446 million (approximately 0.6% above the currently authorized revenue requirement for 2007), a 2009 revenue requirement of \$459 million (approximately 2.8% above the proposed 2008 revenue requirement), and a 2010 revenue requirement of \$471 million (approximately 2.7% above the proposed 2009 revenue requirement). A substantial portion of the authorized revenue requirements, primarily those costs allocated to core customers, will 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 will continue 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 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 36% of the total backbone capacity on the Utility's system. Core customers pay approximately 72% 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 71% to core customers and 29% 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 71% to core customers, 13% to non-core storage service, and 17% 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.

Taken together, the backbone transmission, local transmission, and storage costs that are either protected through balancing accounts or recovered through long-term firm contract reservation charges amount to approximately 49% of the Utility's total revenue requirement for gas transmission and storage.

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 is protected against after-the-fact reasonableness reviews of these gas procurement costs under an incentive mechanism, the CPIM. Under the CPIM, the Utility's purchase costs for a fixed twelve-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 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 shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or \$25 million. 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. The Utility also has received CPUC approval for a long-term gas hedging program on behalf of core customers, through 2011. The costs of the hedging program are recovered directly from gas customers, outside the CPIM mechanism, and are subject only to a compliance review, not an after-the

fact reasonableness review. (For more information see the section entitled “Risk Management Activities” in the 2008 Annual Report).

On June 26, 2008, the CPUC opened a proceeding to examine the California gas utilities’ gas cost incentive mechanisms and the treatment of hedging costs under those incentive mechanisms for core customers. The CPUC will determine whether the utilities’ hedging plans should be incorporated into their incentive mechanisms and whether re-examination of the utilities’ current incentive mechanisms is necessary. It is uncertain when the CPUC will issue a final decision.

Interstate and Canadian Natural Gas Transportation and Storage

The Utility’s interstate and Canadian natural gas transportation agreements with third-party service providers 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 Utility’s agreements with interstate and Canadian natural gas transportation service providers are administered as part of the Utility’s core natural gas procurement business. Their purpose is to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada and the southwestern United States) to the points at which the Utility’s natural gas transportation system begins. For more information see the discussion below under “Natural Gas Utility Operations – Interstate and Canadian Natural Gas Transportation Services Agreements.”

Electric Utility Operations

Electricity Resources

The following table shows the percentage of the Utility’s total sources of electricity for 2008 represented by each major electricity resource:

Owned generation (nuclear, fossil fuel-fired and hydroelectric facilities)	30%
DWR	15%
Qualifying Facilities/Renewables	18%
Irrigation Districts	2%
Other Power Purchases	35%

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under DWR contracts, in the most cost-effective way. Least-cost dispatch requires the Utility, in certain cases, to schedule more electricity than is necessary to meet its retail load and therefore to sell this electricity on the wholesale electricity market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR, based on the percentage of volume supplied by each entity to the Utility’s total load. The Utility’s net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

Owned Generation Facilities

At December 31, 2008, the Utility owned and operated the following generation facilities, all located in California, listed by energy source:

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	107	2,684
Helms pumped storage	Fresno	3	1,212
Hydroelectric subtotal		110	3,896
Fossil fuel:			
Humboldt Bay ⁽¹⁾	Humboldt	2	105
Mobile turbines	Humboldt	2	30
Fossil fuel subtotal		4	135
Total		116	6,271

(1) The Humboldt Bay facilities consist of a retired nuclear generation unit, Humboldt Bay Unit 3, and two operating fossil fuel-fired plants. As described

below, the CPUC has approved the Utility's application to re-power the two fossil fuel-fired plants.

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2, with a total-plant net generation capacity of approximately 2,240 MW of electricity. Unit 1 began commercial operation in May 1985, and the operating license for this unit expires in November 2024. Unit 2 began commercial operation in March 1986, and the operating license for this unit expires in August 2025. For the 10-year period ended December 31, 2008, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 89.9%.

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 17: Commitments and Contingencies— Nuclear Fuel Agreements, of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.

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 51 days. The Utility will replace the steam generators in Unit 1 during the scheduled refueling outage that began in January 2009. Due to this additional work, this refueling outage is expected to last approximately 76 days. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2009	2010	2011	2012	2013
Unit 1					
Refueling	January	October		April	
Duration (days)	76	35		30	
Startup	April	November		May	
Unit 2					
Refueling	October	-	May		February
Duration (days)	35	-	30		30
Startup	November	-	June		March

In addition, as discussed below under “Environmental Matters — Nuclear Fuel Disposal,” in June 2009, the Utility expects to begin loading spent fuel into the newly constructed on-site dry cask storage facility. To provide another storage alternative to the dry cask storage facility, in December 2006, the Utility completed the installation of temporary storage racks in each unit's existing spent fuel storage pool that increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. If there is a delay in loading spent fuel into the dry cask storage facility beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, the operation of Unit 1 may have to be curtailed or halted as early as 2010 and the operation of Unit 2 may have to be curtailed or halted as early as 2011, until such time as additional spent fuel can be safely stored.

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 110 generating units at 69 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 56 diversions, 170 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe, and 5 miles of natural waterways. The system also includes water rights as specified in 90 permits or licenses and 160 statements of water diversion and use. 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. In the last five years, the FERC renewed three hydroelectric licenses with a total of 415 MW of hydroelectric power. The Utility is in the process of renewing licenses for projects with approximately 1,183 MW of additional hydroelectric power. Although the original licenses associated with 599 MW of the 1,183 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,701 MW of hydroelectric power will expire between 2018 and 2043.

New Generation Facilities. In addition to the Utility-owned resources shown in the table above, the Utility has been engaged in the development of three generation facilities to be owned and operated by the Utility. On January 4, 2009, the 530-MW Gateway Generating Station located in Antioch, California, reached full load commercial production and is expected to reach final project completion at the end of the first quarter of 2009. In June 2008, the CPUC approved the construction of the Colusa Generating Station, a 657- MW combined cycle generating facility to be located in Colusa County, California. Final environmental permitting was approved on September 29, 2008 and construction began on October 1, 2008. Subject to meeting operational performance requirements and other conditions, it is anticipated that the Colusa Generating Station will commence operations in 2010. Also, in September 2008, the CEC issued its final decision authorizing the construction of a 163-MW power plant to re-power the Utility's existing power plant at Humboldt Bay, which is at the end of its useful life. Demolition of existing structures on the site is complete and the contractor began preparing the site for construction in December 2008. Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Humboldt Bay project will commence operations in 2010. For more information, see the section of MD&A entitled “Capital Expenditures — New

Generation Facilities” in the 2008 Annual Report.

DWR Power Purchases

During 2008, electricity from the DWR contracts allocated to the Utility provided approximately 15% of the electricity delivered to the Utility's customers. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of these DWR contracts and acts as a billing and collection agent. The DWR remains legally and financially responsible for its contracts. The Utility expects that the amount of power supplied under the DWR's contracts will diminish in the future as the contracts expire or terminate. For more information regarding the DWR contracts, see Note 17: Commitments and Contingencies – California Department of Water Resources Contracts, of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.

Third-Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements. As of December 31, 2008, the Utility had power purchase agreements with 246 QFs for approximately 3,900 MW that are in operation. Agreements for approximately 3,600 MW expire at various dates between 2009 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. The Utility also has power purchase agreements with approximately 74 inoperative QFs. The total of approximately 3,900 MW consists of roughly 2,500 MW from cogeneration projects, 600 MW from wind projects and 800 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar, and hydroelectric. QF power purchase agreements accounted for approximately 18%, 20%, and 20%, of the Utility's 2008, 2007, and 2006 electricity sources, respectively. No single QF accounted for more than 5% of the Utility's 2008, 2007, or 2006 electricity sources.

Irrigation Districts and Water Agencies. The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, whether or not any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2010 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 2%, 3%, and 6% of the Utility's electricity sources in 2008, 2007, and 2006, respectively.

Renewable Energy Contracts. California law requires each California retail seller of electricity, except for municipal utilities, to increase its purchases of renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy) by at least 1% of its retail sales, so that the amount of electricity delivered from renewable resources equals at least 20% of its total retail sales by the end of 2010. During 2008, the Utility entered into new renewable power purchase contracts that will help the Utility meet this RPS by 2010.

Long-Term Power Purchase Agreements. In accordance with the Utility's CPUC-approved long-term procurement plans, the Utility has entered into several power purchase agreements with third parties. The Utility's obligations under a portion of these agreements are contingent on the third party's development of a new generation facility to provide the power to be purchased by the Utility under the agreements.

For more information regarding the Utility's power purchase contracts, see Note 17: Commitments and Contingencies— Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.

Future Long-Term Generation Resources

The Utility's CPUC-approved long-term electricity procurement plan, covering procurement during 2007-2016, forecasts that the Utility will need to obtain an additional 800 to 1,200 MW of new conventional generation by 2015 above the Utility's planned additions of renewable resources, energy efficiency, demand reduction programs, and previously approved contracts for new generation resources.

The utilities are permitted to acquire ownership of new conventional generation resources only through purchase and sale agreements (“PSAs”) (*i.e.*, a PSA is a “turnkey” arrangement in which a new generating facility is constructed by a third party and then sold to the Utility upon satisfaction of certain contractual requirements) and engineering, construction, and procurement arrangements proposed by third parties. The utilities are prohibited from submitting offers for utility-build generation in their respective RFOs until questions can be resolved about how to compare offers for utility-owned generation with offers from independent power producers. The utilities are permitted to propose utility-owned generation projects through a separate application outside of the RFO process in the following circumstances: (1) to mitigate market power demonstrated by the utility to be held by others, (2) to support a use of preferred resources, such as renewable energy sources, (3) to take advantage of a unique and fleeting

opportunity (such as a bankruptcy settlement), and (4) to meet unique reliability needs. On July 21, 2008, the Utility received offers from third parties in response to the Utility's April 1, 2008 RFO for 800 MW to 1,200 MW of dispatchable and operationally flexible new generation resources to be on-line no later than May 2015. The Utility's RFO requested offers for both PSAs and power purchase agreements. In the fourth quarter of 2008 the Utility developed its RFO shortlist of participants and is currently involved in negotiations with potential counterparties. The Utility anticipates executing contracts and requesting CPUC approval of the executed contracts in the first half of 2009.

In addition, on February 24, 2009, the Utility requested the CPUC to approve the Utility's proposed development of renewable generation resources based on solar photovoltaics ("PV") technology. The Utility's proposal includes the development and construction of up to 250 MW of Utility-owned PV generating facilities, to be deployed over a period of five years and the execution of power purchase agreements for up to 250 MW of PV projects to be developed by independent power producers. For more information regarding the Utility's proposal, see the section of MD&A entitled "Capital Expenditures — Proposed New Generation Facilities" in the 2008 Annual Report.

Electricity Transmission

At December 31, 2008, the Utility owned 18,650 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 56,401 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 141,036 circuit miles of distribution lines and substations with a capacity of 27,137 MVA. In 2008, the Utility delivered 88,127 GWh to its customers; including 6,191 GWh delivered to direct access customers. The Utility is interconnected with electric power systems in the WECC, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

During 1998, in connection with electric industry restructuring, the California investor-owned electric utilities relinquished control, but not ownership, of their transmission facilities to the CAISO. The Utility entered into a Transmission Control Agreement with the CAISO and other participating transmission owners (including Southern California Edison Company, San Diego Gas & Electric Company, and several California municipal utilities) under which the transmission owners have assigned operational control of their electric transmission systems to the CAISO. The Utility is required to give the CAISO two years notice and receive approval from the FERC if it wishes to withdraw from the Transmission Control Agreement and take back operational control of its transmission facilities.

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 a 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 following EPAct, 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 above under "The Utility's Regulatory Environment-Federal Energy Regulation."

The Utility expects to undertake various additional transmission projects over the next few years to upgrade and expand the Utility's transmission system in order to accommodate system load growth, to secure access to renewable generation resources, to replace aging or obsolete equipment, to maintain system reliability, and to reduce reliance on generation provided under reliability must run ("RMR") agreements with the CAISO. (RMR agreements require various power plant owners, including the Utility, to keep designated units in certain power plants, known as RMR units, available to generate electricity upon the CAISO's demand when the generation from those RMR units is needed for local transmission system reliability.) Potential transmission projects include a 500-kV transmission line to improve access to new renewable generation resources and to reduce RMR generation contracts in the Fresno, California area (referred to as the "Central California Clean Energy Transmission Project") and a high voltage transmission line between Northern California and British Columbia, Canada to access renewable generation resources in British Columbia. In addition, the Utility is currently working with several stakeholders in the western United States to assess the feasibility of new large-scale electric transmission expansion projects to address regional electricity needs over the long term.

Electricity Distribution Operations

The Utility's electricity distribution network extends through 47 of California's 58 counties, comprising most of northern and central California. The Utility's network consists of 141,036 circuit miles of distribution lines (of which approximately 19% are underground and approximately 81% are overhead). There are 92 transmission substations and 48 transmission-switching stations. A transmission substation is a fenced facility where voltage is transformed from one transmission voltage level to another. The Utility's network includes 607 distribution substations and 110 low-voltage distribution substations. The 49 combined transmission and distribution substations have both transmission and distribution transformers.

The Utility's distribution network interconnects to the Utility's electricity transmission system at 1,106 points. This interconnection between the Utility's distribution network and the transmission system typically occurs at 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.

During 2006, the Utility began the installation of an advanced metering infrastructure, known as the SmartMeter™ program, for virtually all of the Utility's electric and gas customers. These meters enable the Utility to measure usage on an hourly basis for electricity and on a daily basis for natural gas, which can allow for demand-response rates to encourage customers to reduce energy consumption during peak demand periods, thus reducing peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility expects to complete the installation of the network infrastructure and advanced meters throughout its service territory by the end of 2011. The Utility also has requested the CPUC to approve the Utility's proposal to upgrade elements of the Utility's SmartMeter™ program. The Utility seeks approval to install solid-state electric meters and associated devices that would offer an expanded range of service features for customers and increased operational efficiencies for the Utility. These upgraded meters and associated devices would provide additional energy conservation and demand response options for electric customers. In addition, the solid-state electric meters are designed to facilitate the Utility's ability to incorporate future advanced metering technology innovations in a timely and cost-effective manner. (For more information about the advanced metering infrastructure, see the section of MD&A entitled "Capital Expenditures — SmartMeter™ Program" in the 2008 Annual Report.)

2008 Electricity Deliveries. The following table shows the percentage of the Utility's total 2008 electricity deliveries represented by each of its major customer classes:

Total 2008 Electricity Delivered: 88,127 GWh

Agricultural and Other Customers	7%
Industrial Customers	18%
Residential Customers	36%
Commercial Customers	39%

Electricity Distribution Operating Statistics

The following table shows certain of the Utility's operating statistics from 2004 to 2008 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2008	2007	2006	2005	2004
Customers (average for the year):					
Residential	4,488,884	4,464,483	4,417,638	4,353,458	4,366,897
Commercial	527,045	521,732	515,297	509,786	509,501
Industrial	1,265	1,261	1,212	1,271	1,339
Agricultural	81,757	80,366	79,006	78,876	80,276
Public street and highway lighting	30,474	29,643	28,799	28,021	27,176
Other electric utilities	2	2	4	4	3
Total ⁽¹⁾	5,129,427	5,097,487	5,041,956	4,971,416	4,985,192
Deliveries (in GWh): ⁽²⁾					
Residential	31,454	30,796	31,014	29,752	29,453
Commercial	34,053	33,986	33,492	32,375	32,268
Industrial	16,148	15,159	15,166	14,932	14,796
Agricultural	5,594	5,402	3,839	3,742	4,300
Public street and highway lighting	877	833	785	792	2,091
Other electric utilities	1	3	14	33	28
Subtotal	88,127	86,179	84,310	81,626	82,936
California Department of Water Resources (DWR)	(13,344)	(21,193)	(19,585)	(20,476)	(19,938)
Total non-DWR electricity	74,783	64,986	64,725	61,150	62,998
Revenues (in millions):					
Residential	\$ 4,656	\$ 4,580	\$ 4,491	\$ 3,856	\$ 3,718
Commercial	4,413	4,484	4,414	4,114	4,179
Industrial	1,400	1,252	1,293	1,232	1,204
Agricultural	727	664	483	446	491
Public street and highway lighting	75	78	72	66	71
Other electric utilities	126	85	59	4	22
Subtotal	11,397	11,143	10,812	9,718	9,685
DWR	(1,325)	(2,229)	(2,119)	(1,699)	(1,933)
Direct access credits	—	—	—	—	—
Miscellaneous	336	215	261	235	(248)
Regulatory balancing accounts	330	352	(202)	(327)	363
Total electricity operating revenues	\$ 10,738	\$ 9,481	\$ 8,752	\$ 7,927	\$ 7,867
Other Data:					
Average annual residential usage (kWh)	7,007	6,898	7,020	6,834	6,744
Average billed revenues (cents per kWh):					
Residential	14.80	14.87	14.48	12.96	12.62
Commercial	12.96	13.19	13.18	12.71	12.95
Industrial	8.67	8.26	8.53	8.25	8.14
Agricultural	13.00	12.29	12.58	11.92	11.41
Net plant investment per customer	\$ 3,994	\$ 3,418	\$ 3,148	\$ 2,966	\$ 2,790

- (1) Starting in 2005, the Utility's methodology used to count customers changed from the number of billings to the number of active service agreements.
- (2) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

Natural Gas Utility Operations

The Utility owns and operates an integrated natural gas transportation, storage and distribution system in California that extends throughout all or a part of 40 of California's 58 counties and includes most of northern and central California. In 2008, the Utility served approximately 4.3 million natural gas distribution customers. The total volume of natural gas throughput during 2008 was approximately 839 Bcf.

As of December 31, 2008, the Utility's natural gas system consisted of 42,017 miles of distribution pipelines, 6,418 miles of backbone and local transmission pipelines, and three storage facilities. 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, which interconnects with the U.S. Southwest and Rocky Mountain pipeline systems owned by third parties (Transwestern Pipeline Co., El Paso Natural Gas Company, Questar Southern Trails Pipeline Company and Kern River Pipeline Company), has a receipt capacity of approximately 1.07 Bcf per day. The Utility's Line 400/401 interconnects with the natural gas transportation pipeline of Gas Transmission Northwest Corporation at the California-Oregon border. This line has a receipt capacity at the border of approximately 2.02 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 also owns and operates three underground natural gas storage fields connected to the Utility's transmission and storage system. These storage fields have a combined firm capacity of approximately 47 Bcf. In addition, two independent storage operators are interconnected to the Utility's northern California transportation system.

The Utility, along with Gill Ranch Storage, LLC, a subsidiary of Northwest Natural Gas Company, is developing an underground natural gas storage facility near Fresno, California. It is expected that construction of the initial phase, to consist of approximately 20 Bcf of total capacity, will be completed in 2010. The Utility has a 25% interest in the initial phase of the proposed storage facility. Development of the storage facility is subject to CPUC approval, including the CPUC's environmental review as required by the California Environmental Quality Act. The Utility expects the CPUC to issue a final decision in late 2009.

The CPUC divides the Utility's natural gas customers into two categories: 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 smaller commercial natural gas customers. The non-core customer class is comprised of industrial, larger commercial and electric generation natural gas customers. In 2008, core customers represented more than 99% of the Utility's total customers and 37% of its total natural

gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and 63% of its total natural gas deliveries.

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 99% of core customers, representing over 96% of core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers. However, some non-core customers are permitted to elect core service and receive Utility procurement service through that avenue. Electricity generators, QF cogenerators, enhanced oil recovery customers, refiners, and other large non-core customers may not elect core service, and smaller non-core customers must contract for a minimum five-year term if they elect core service. These restrictions were put in place because large increases in demand for the Utility's procurement service caused by significant transfers of non-core customers to core service would raise prices for all other core procurement customers and obligate the Utility to reinforce its pipeline system to provide core service reliability on a short-term basis to serve this new load.

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 or changes in their consumption levels. The Utility's results of operations can, however, be affected 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 3% are recovered from non-core customers.

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 2008 California Gas Report forecasts average annual growth in the Utility's natural gas deliveries (for core customers and non-core transportation) of approximately 0.2% for the years 2008 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.

2008 Natural Gas Deliveries. The following table shows the percentage of the Utility's total 2008 natural gas deliveries represented by each of the Utility's major customer classes:

Total 2008 Natural Gas Deliveries: 839 Bcf

Residential Customers	26%
Transport-only Customers (non-core)	63%
Commercial Customers	11%

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2004 through 2008 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2008	2007	2006	2005	2004
Customers (average for the year):					
Residential	4,043,616	4,030,499	3,989,331	3,929,117	3,812,914
Commercial	224,617	223,330	220,024	216,749	215,547
Industrial	926	958	988	962	2,178
Other gas utilities	6	6	6	6	6
Total	4,269,165	4,254,793	4,210,349	4,146,834	4,030,645
Gas supply (MMcf):					
Purchased from suppliers in:					
Canada	189,608	199,870	202,274	204,884	205,180
California	(53,126)	(23,065)	(13,401)	(18,951)	(9,108)
Other states	123,833	101,271	103,658	103,237	103,801
Total purchased	260,315	278,076	292,531	289,170	299,873
Net (to storage) from storage	560	(1,120)	4,359	(3,659)	(532)
Total	260,875	276,956	296,890	285,511	299,341
Utility use, losses, etc. ⁽¹⁾	1,758	(12,760)	(27,610)	(14,312)	(19,287)
Net gas for sales	262,633	264,196	269,280	271,199	280,054
Bundled gas sales (MMcf):					
Residential	198,699	196,903	196,092	194,108	201,601
Commercial	63,934	67,293	73,178	77,056	78,080
Industrial	—	—	10	35	373
Other gas utilities	—	—	—	—	—
Total	262,633	264,196	269,280	271,199	280,054
Transportation only (MMcf):	569,535	605,259	559,270	572,869	597,706
Revenues (in millions):					
Bundled gas sales:					
Residential	\$ 2,574	\$ 2,378	\$ 2,452	\$ 2,336	\$ 1,944
Commercial	792	766	859	885	712
Industrial					
Other gas utilities					

Miscellaneous	(30)	87	121	(22)	(29)
Regulatory balancing accounts	221	186	40	340	316
Bundled gas revenues	3,557	3,417	3,472	3,539	2,943
Transportation service only revenue	333	340	315	237	270
Operating revenues	\$ 3,890	\$ 3,757	\$ 3,787	\$ 3,776	\$ 3,213
Selected Statistics:					
Average annual residential usage (Mcf)	49	49	49	49	53
Average billed bundled gas sales revenues per Mcf:					
Residential	\$ 12.95	\$ 12.07	\$ 12.50	\$ 12.04	\$ 9.64
Commercial	12.38	11.38	11.73	11.48	9.12
Industrial			1.03	0.61	(0.56)
Average billed transportation only revenue per Mcf	0.59	0.56	0.56	0.42	0.45
Net plant investment per customer	\$ 1,344	\$ 1,375	\$ 1,304	\$ 1,262	\$ 1,266

(1) Includes fuel for the Utility's fossil fuel-fired generation plants.

Natural Gas Supplies

The Utility purchases natural gas to serve the Utility's 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 2008, the Utility purchased approximately 260,315 MMcf of natural gas (net of the sale of excess supply) from suppliers. Consistent with existing CPUC policy directives, 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 2008.

The following table shows the total volume and the average price of natural gas in dollars per MMcf of the Utility's natural gas purchases by region during each of the last five years. The average prices for Canadian and U.S. Southwest gas shown below include the commodity natural gas prices, pipeline demand or reservation charges, transportation charges and other pipeline assessments. The volumes purchased are shown net of sales of excess supplies of gas. In 2008, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2008		2007		2006		2005		2004	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	189,608	\$8.29	199,870	\$6.63	202,274	\$6.27	204,884	\$7.12	205,180	\$5.37
California ⁽¹⁾	(53,126)	\$9.24	(23,065)	\$6.77	(13,401)	\$7.04	(18,951)	\$7.70	(9,108)	\$4.89
Other states (substantially all U.S. southwest)	123,833	\$7.05	101,271	\$6.30	103,658	\$6.51	103,237	\$7.10	103,801	\$5.44
Total/weighted average	260,315	\$7.51	278,076	\$6.50	292,531	\$6.32	289,170	\$7.07	299,873	\$5.41

(1) California purchases include supplies from various California producers and supplies transported into California by others.

Gas Gathering Facilities

The Utility's gas gathering system collects natural gas from third-party wells in California. During 2008, approximately 6% of the gas transported on the Utility's system came from various California producers, with the balance coming from supplies transported into California by others. The natural gas well production is processed by producers to remove various impurities from the natural gas stream and the Utility then odorizes the natural gas so that it may be detected in the event of a leak. The facilities include approximately 110.3 miles of gas gathering pipelines. The Utility receives gas well production at approximately 188 metering facilities. The Utility's gas gathering system is geographically dispersed and is located in 8 California counties. Approximately 138 MMcf per day of natural gas produced in northern California was delivered into the Utility's gas gathering system during 2008.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2008, approximately 52% of the gas transported on the Utility's system came from western Canada. 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- Canadian 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 TransCanada's Gas Transmission Northwest Corporation ("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 a firm transportation agreement with GTN for these services. As described below, as part of the FERC-approved all-party settlement of GTN's most recent general rate case, the Utility's contract with GTN will be replaced beginning November 1, 2009 by three smaller contracts totaling the same amount with staggered terms.

During 2008, approximately 42% of the gas transported on the Utility's system came from the western United States, excluding California. The Utility has firm transportation agreements with Transwestern Pipeline Company 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.

The following table shows certain information about the Utility's firm natural gas transportation agreements in effect during 2008, including the contract quantities, contract durations and associated demand charges, net of sales of excess supplies, for capacity reservations. These agreements require the Utility to pay fixed demand charges for reserving firm capacity on the pipelines. The total demand charges may change periodically as a result of changes in regulated tariff rates approved by Canadian regulators in the case of TransCanada NOVA Gas Transmission, Ltd. and TransCanada Foothills Pipe Lines Ltd., B.C. System, and by the FERC in all other cases. The Utility may, upon prior notice and with the CPUC's approval, extend each of these natural gas transportation agreements. On the FERC-regulated pipelines, the Utility has either a right of first refusal or evergreen rights allowing it to renew natural gas transportation agreements at the end of their terms. If another prospective shipper also wants the capacity, the Utility would be required to match the competing bid with respect to both price and term.

Pipeline	Expiration Date	Quantity MDth per day	Demand Charges for the Year Ended December 31, 2008 (In millions)
TransCanada NOVA Gas Transmission, Ltd.	10/31/2011 ⁽¹⁾	619	\$29.5
TransCanada Foothills Pipe Lines Ltd., B.C. System	10/31/2011	611	15.7
Gas Transmission Northwest Corporation	10/31/2009	610	89.6
Transwestern Pipeline Company ⁽¹⁾	Various	180	15.9
El Paso Natural Gas Company ⁽²⁾	Various	267	17.2

(1) As of December 31, 2008, the Utility had two active contracts with Transwestern Pipeline Company with expiration dates ranging from February 28, 2009 to March 31, 2010.

(2) As of December 31, 2008, the Utility had three active contracts with El Paso Natural Gas Company with expiration dates ranging from February 28, 2009 to June 30, 2012.

As required by the all-party settlement of GTN's most recent general rate case approved by the FERC on January 7, 2008, the Utility has entered into three smaller contracts with GTN with terms that begin on November 1, 2009 and terminate on various dates unless renewed, as follows:

Expiration Date	Quantity MDth per day	Estimated Demand Charges 2009-2011 (In millions)
10/31/2011	250	\$58
10/31/2016	280	71
10/31/2020	80	20

Also, as part of the same settlement, the Utility has entered into a separate contract with GTN for firm transportation service to support the Utility's need for natural gas for electric power plant fuel. This new contract is for a quantity of 50 MDth/d for a 59-month term, July 1, 2009, through May 31, 2014.

In addition, in December 2008, the CPUC approved an agreement between the Utility and El Paso Corporation for the Utility to subscribe for 375 MDth per day of firm service rights on El Paso Corporation's proposed 680-mile, 42-inch natural gas transmission pipeline (the "Ruby Pipeline") that would begin at the Opal Hub in Wyoming and terminate at the Malin, Oregon, interconnect, near California's northern border. The Ruby Pipeline is expected to have an initial capacity of 1.2 Bcf per day and be expandable to 2 Bcf per day. The proposed Ruby Pipeline would connect Rocky Mountain natural gas producers with northern California, Nevada, and the Pacific Northwest to provide natural gas users with competitively priced natural gas. Subject to obtaining the required regulatory and other approvals and necessary customer commitments, the Ruby Pipeline is anticipated to be in service in the first quarter of 2011.

Environmental Matters

The following discussion includes certain forward-looking information relating to estimated expenditures for environmental protection measures and the possible future impact of environmental compliance measures. The information below reflects current estimates, which are periodically evaluated and revised. Future estimates and actual results may differ materially from those indicated below. These estimates are subject to a number of assumptions and uncertainties, 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, and the availability of recoveries or contributions from third parties.

General

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 discharge of pollutants into air, water and soil;
- the identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting, remediation and emergency response in connection with hazardous and radioactive substances; and
- 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 marketable 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.

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 sites that contain hazardous substances are subject to a special ratemaking mechanism under which the Utility is authorized to recover hazardous waste remediation costs for environmental claims from customers (*e.g.* , for costs of cleaning up the Utility's facilities and sites where the Utility's hazardous substances have been sent). This mechanism allows the Utility to include 90% of eligible hazardous waste remediation costs in the Utility's rates without a reasonableness review. (One exception to this is the Hinkley natural gas compressor site discussed below. The cost of environmental remediation associated with this site is not recoverable from customers.) Ten percent of any net insurance recoveries associated with hazardous waste remediation sites are assigned to the Utility's customers. The balances of any insurance recoveries (90%) are retained by the Utility until it has been reimbursed for the 10% share of clean-up costs not included in rates. Any insurance recoveries above full cost reimbursement levels are allocated 60% to customers and 40% to the Utility. Finally, 10% of any

recoveries from the Utility's claims against third parties associated with hazardous waste remediation sites are retained by the Utility, with the remainder, 90% of any such recoveries, assigned to the Utility's customers.

Hazardous waste remediation costs are rising and are likely to be significant into the foreseeable future. Based on the Utility's past experience, it believes that it can recover most of the future costs that it may incur to remediate hazardous waste through rates and insurance recoveries. The Utility cannot provide assurance, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

For more information about environmental remediation liabilities, see Note 17 of the "Notes to the Consolidated Financial Statements" in the 2008 Annual Report.

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, nitrogen oxide and particulate matter. In addition, various laws and regulations addressing climate change and greenhouse gas emissions ("GHG") are being considered or implemented at the federal and state levels, as discussed below. Fossil fuel-fired plants and gas compressor stations used in the Utility's pipeline operations are sources of air pollutants and, therefore, are subject to substantial regulation and enforcement oversight by the applicable governmental agencies. In addition, greenhouse gas emissions from natural gas consumed by the Utility's customers would be subject to regulation by the California Air Resources Board ("CARB"), as discussed below.

At the federal level, several legislative initiatives have been introduced recently in Congress aimed at addressing climate change through imposition of nation-wide regulatory limits on the emissions of GHGs. No such legislation has yet been enacted by Congress, but extensive hearings and discussion are expected in the coming year. At the state level, California enacted Assembly Bill 32 ("AB 32"), the California Global Warming Solutions Act of 2006, to address climate change. AB 32 requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. AB 32 also authorizes the CARB to monitor and enforce compliance with the GHG reduction program and to consider implementing market-based mechanisms, including trading of GHG emissions allowances. In 2007, the CARB adopted a state-wide GHG 1990 emissions baseline of 427 million metric tons of carbon dioxide (or its equivalent). This 1990 baseline serves as the 2020 emissions reduction target for the state of California. (The CARB has not yet determined specific GHG reduction limits applicable to the utility sector or individual utilities within the utility sector.) In 2007, the CARB also adopted a regulation that requires the California investor-owned utilities and other GHG emitters to file verified reports of their annual GHG emissions. On December 12, 2008, the CARB adopted a scoping plan that contains recommendations for achieving the maximum technologically feasible and cost-effective GHG reductions to meet the 2020 reduction target, including increased reliance on renewable resources and energy efficiency and the development of a multi-sector cap-and-trade program. The CARB is required to adopt regulations to implement the scoping plan not later than January 1, 2011 to become effective on January 1, 2012.

California Senate Bill 1368, enacted in 2006, prohibits any load-serving entity in California, including investor-owned electric utilities, from entering into a long-term financial commitment for baseload electricity generation unless the generation complies with a GHG emission performance standard. As required by Senate Bill 1368, on January 25, 2007, the CPUC adopted an interim GHG emissions performance standard of 1,100 pounds of carbon dioxide per MWh that applies to new commitments for baseload electricity procured under contracts with a term of five years or longer or generated by the Utility. After a state-wide GHG emissions limit is established and is in operation, in accordance with AB 32, the CPUC will re-evaluate its interim GHG emissions performance standard and determine whether to continue, modify or rescind it.

These California laws, as well as current federal and other state regulatory initiatives relating to emissions of carbon dioxide and other GHGs, particulates and other pollutants, could cause the Utility's compliance costs and capital expenditures to increase. Although the Utility's existing and forecast emissions of GHGs are relatively low compared to average emissions by other electric utilities and generators elsewhere in the country, these laws could require the Utility to replace equipment, install additional pollution controls, purchase various emission allowances at as yet undefined prices, or curtail operations. The Utility expects that it will recover the associated costs and capital expenditures in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

Water Quality

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act National Pollutant Discharge Elimination System ("NPDES") 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 Diablo Canyon power plant's discharge was not protective of beneficial uses. For more information, see the discussion below in "Item 3—Legal Proceedings—Diablo Canyon Power Plant."

There is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. In July 2004, the U.S. Environmental Protection Agency ("EPA") issued regulations to implement Section 316(b) intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations provided each facility with a number of compliance options and permitted site-specific variances based on a cost-benefit analysis. The EPA regulations also allowed the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, the California State Water Resources Control Board ("Water Board") issued a proposed policy to address once-through cooling. The Water Board's current proposal would require the installation of cooling towers at nuclear facilities by January 1, 2021, unless the installation of cooling towers would conflict with a nuclear safety requirement. Further, in January 2009, legislation proposed in the California Senate would ban once-through cooling, effective January 2015.

Various parties separately challenged the EPA's regulations and in January 2007, the U.S. Court of Appeals for the Second Circuit ("Second Circuit") issued a decision holding that environmental restoration cannot be used as a compliance option and that site-specific compliance variances based on a cost-benefit test could not be used. The Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and in July 2007, the EPA suspended its regulations. The U.S. Supreme Court is expected to issue a decision by mid-2009 regarding the cost-benefit test. Depending on the form of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If the final regulations adopted by the EPA, the Water Board, or the California Legislature, require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge.

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.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements issued by the EPA under the 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 assesses, on an ongoing basis, measures that may be necessary to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility has a comprehensive program to comply with hazardous waste storage, handling and disposal requirements issued by the EPA under RCRA and CERCLA, state hazardous waste laws and other environmental requirements.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, compressor stations and sites where the Utility stores, recycles and disposes of potentially hazardous materials. 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.

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. Additionally, the Utility's Hunters Point power plant in San Francisco closed in May 2006 and is in the decommissioning process. Remedial investigations are substantially complete, and the Utility anticipates that the California Department of Toxic Substances Control will approve the remediation plan by the second quarter of 2009. The Utility spent approximately \$1 million in 2008 and estimates that it will spend approximately \$12 million in 2009 and approximately \$15 million in 2010 for remediation at this site.

In addition, the federal Toxic Substances Control Act regulates the use, disposal and clean-up of polychlorinated biphenyls ("PCBs"), which are used in certain electrical equipment. The Utility has removed from service all of the distribution capacitors and network transformers containing high concentrations of PCBs, representing the vast majority of PCBs that had existed in the Utility's electricity distribution system.

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain retired manufactured gas plant sites. During their operation, from the mid-1800s through the early 1900s, manufactured gas plants produced lampblack and tar residues. The residues from these operations, which may remain at some sites, contain chemical compounds that now are classified as hazardous. There are 95 such sites within the Utility's service territory that are owned by the Utility or third parties. The Utility has determined that it is liable for the remediation of 41 sites, is potentially liable for remediation of an additional 24 sites, and is not liable for remediation at the remaining 30 sites. The Utility has a program, in cooperation with environmental agencies and third party owners, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at the 41 sites for which the Utility is liable. The Utility spent approximately \$12 million in 2008 and expects to spend approximately \$27 million in 2009 and \$20 million in 2010 on these sites. The Utility expects that expenses at these sites will increase as remedial actions related to these sites are approved by regulatory agencies and claims by third party owners are settled. Although it is likely that the Utility will incur remediation costs related to some of these sites, the Utility cannot quantify the potential amount.

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 five 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. Other responsible parties are involved with the Utility in investigation and cleaning up the three other disposal sites with oversight from the regulatory agencies. The Utility contributes to these sites under cost sharing agreements or court approved settlements

In addition, the Utility has been named as a defendant in a civil lawsuit in which plaintiffs allege that the Utility is responsible for performing or paying for remedial action at sites that it no longer owns or never owned. Remedial actions may include investigations, health and ecological assessments, and removal of wastes.

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 has a comprehensive program to monitor a network of groundwater wells at both the Hinkley and Topock natural gas compressor stations. At Hinkley, the Utility is cooperating with the Regional Water Quality Control Board to evaluate and remediate the chromium groundwater plume. Measures have been implemented to control movement of the plume, while full-scale in-situ treatment systems operate to reduce the mass of the plume. An evaluation of the performance of these interim remedy measures, as well as possible future measures, is underway as part of the development of a final remedy at the Hinkley site. In 2008, the Utility spent approximately \$15 million on remediation activities at Hinkley, and currently estimates it will spend at least \$16 million in 2009 and \$6 million in 2010. Environmental remediation costs associated with the Hinkley natural gas compressor site are not recoverable from customers.

At the Topock gas compressor station, located near Needles, California, the Utility has implemented interim measures including a system of extraction wells and a treatment plant designed to prevent movement of a hexavalent chromium plume toward the Colorado River. In addition, the Utility is working with the agencies to complete investigations at this site and to develop a long-term plan for clean up of the plume. A final cleanup draft plan has been developed for agency and stakeholder review; approval of a final version of that plan is scheduled to occur by the first quarter of 2010. In 2008, the Utility spent approximately \$23 million on the interim measures and for work on the long term site solution. The Utility currently estimates that it will spend at least \$19 million

in 2009 and \$18 million in 2010 for remediation activities at Topock. Although work at the Topock site poses several technical and regulatory obstacles, the Utility's remediation costs for Topock are subject to the ratemaking mechanism described above. The Utility does not expect the remediation of the Topock and Hinkley gas compressor sites to have a material adverse effect on its results of operations or financial condition. The Utility does not expect that it will incur any material expenditures related to any remediation at its Kettleman natural gas compressor station.

Nuclear Fuel Disposal

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the DOE and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay. The DOE failed to develop a permanent storage site by January 31, 1998. The Utility believes that the existing spent fuel pools at Diablo Canyon (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until October 2010 for Unit 1 and May 2011 for Unit 2. Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit (the "Ninth Circuit") issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of a terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility.

In October 2008, the NRC rejected the final contention that had been made during the appeal. The appellant has filed a petition for review of the NRC's order in the Ninth Circuit. Although the appellant did not seek to obtain an order prohibiting the Utility from loading spent fuel, the petition stated that they may seek a stay of fuel loading at the facility. On December 31, 2008, the appellate court granted the Utility's request to intervene in the proceeding. All briefs by all parties are scheduled to be filed by April 8, 2009.

The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage is expected to begin in June 2009. If the Utility is unable to begin loading spent fuel by October 2010 for Unit 1 or May 2011 for Unit 2 and if the Utility is otherwise unable to increase its on-site storage capacity, the Utility would have to curtail or halt operations in the unit until such time as additional safe storage for spent fuel is made available.

As a consequence of the DOE's failure to develop a permanent national repository for spent nuclear fuel and high-level radioactive waste, the Utility and other nuclear power plant owners sued the DOE for breach of contract. In October 2006, the U.S. Court of Federal Claims found the DOE had breached its contract and awarded the Utility approximately \$42.8 million of the \$92 million incurred by the Utility through 2004 to construct on-site storage at Diablo Canyon and Humboldt Bay Unit 3. Following the Utility's appeal of the award, the U.S. Court of Appeals for the Federal Circuit reversed the lower court on issues relating to the calculation of damages and ordered the lower court to re-calculate the award. Although various motions by the DOE for reconsideration are still pending, the judge in the lower court conducted a status conference on January 15, 2009 and has scheduled another conference for July 9, 2009. The Utility expects the final award will approximate \$91 million for costs incurred through 2004 and that the Utility will recover all of its costs incurred after 2004 to build on-site storage facilities. Amounts recovered from the DOE will be credited to customers through rates.

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 makes contributions to trusts to provide for the eventual decommissioning of each nuclear unit. In the Utility's 2005 Nuclear Decommissioning Cost Triennial Proceeding, used to determine the level of Utility trust contributions and related revenue requirement, the CPUC assumed that the eventual decommissioning of Diablo Canyon Unit 1 would be scheduled to begin in 2024 and be completed in 2044; that decommissioning of Diablo Canyon Unit 2 would be scheduled to begin in 2025 and be completed in 2041; and that decommissioning of Humboldt Bay Unit 3 would be scheduled to begin in 2009 and be completed in 2015. A premature shutdown of the Diablo Canyon units would increase the likelihood of an earlier start to decommissioning. The Utility's decommissioning cost estimates are based on the 2005 decommissioning cost studies, prepared in accordance with CPUC requirements. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements,

technology, and costs of labor, materials and equipment. The Utility recovers its revenue requirements for estimated nuclear decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities.

For more information about nuclear decommissioning, including the estimated decommissioning costs, see Note 13 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.

Electric and Magnetic Fields

Electric and magnetic fields ("EMFs") naturally result from the generation, transmission, distribution and use of electricity. In November 1993, the CPUC adopted an interim EMF policy for California energy utilities that, among other things, requires California energy utilities to take no-cost and low-cost steps to reduce EMFs from new or upgraded utility facilities. California energy utilities were required to fund an EMF education program and an EMF research program managed by the California Department of Health Services. In October 2002, the California Department of Health Services released its report to the CPUC and the public, based primarily on its review of studies by others, evaluating the possible risks from EMFs. The report's conclusions contrast with other recent reports by authoritative health agencies in that the California Department of Health Services' report has assigned a higher probability to the possibility of a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis and miscarriages.

On January 26, 2006, the CPUC issued a decision which affirms the CPUC's "low-cost/no-cost, prudent avoidance" policy to reduce EMF exposure for new utility transmission and substation projects. The CPUC ordered the continued use of a 4% of project cost benchmark for EMF reduction measures. The CPUC also reaffirmed that it has exclusive jurisdiction with respect to utility EMF matters.

The Utility currently is not involved in third-party litigation concerning EMFs. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMFs from power lines. In a case involving allegations of personal injury, a California appeals court held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMFs, and barred plaintiffs' personal injury claims. The California Supreme Court declined to hear the plaintiffs' appeal of this decision.

Item 1A. Risk Factors

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading "Risk Factors" in the MD&A in the 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report.

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, all of which are described above under "Electric Utility Operations" and "Natural Gas Utility Operations." In total, the Utility occupies 9.8 million square feet of real property, including 8.5 million square feet that the Utility owns. Of the 9.8 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 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. The Utility currently owns approximately 167,000 acres of land, approximately 140,000 acres of which it will encumber with conservation easements and/or donate to public agencies or non-profit conservation organizations under the Chapter 11 Settlement Agreement. Approximately 75,000 acres of this land may be donated in fee and encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and will only be encumbered with conservation easements. As contemplated in the Chapter 11 Settlement Agreement, the Utility formed an entity, 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 140,000 acres. The Council is governed by an 18-member Board of Directors that represents 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 Utility has appointed 1 out of 18

members of the Board of Directors of the Council. In December 2007, the Council adopted the LCP and submitted it to the Utility.

The Utility has accepted the LCP and will seek authorization from the CPUC, the FERC and other approving entities to proceed with the transactions necessary to implement the LCP.

PG&E Corporation also leases approximately 74,000 square feet of office space from a third party in San Francisco, California. This lease expires in 2012.

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.

Diablo Canyon Power Plant

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately \$6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the NPDES permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately \$30 million. The Utility would seek to recover these costs through rates charged to customers. The Water Board is developing a state policy for the implementation of Section 316(b) of the Clean Water Act, the adoption of which could affect future negotiations between the Central Coast Board and the Utility. For more information about the draft state policy, see "Environmental Matters—Water Quality" above.

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

Complaints Filed by the California Attorney General and the City and County of San Francisco

On January 10, 2002, the California Attorney General filed a complaint in the Superior Court for the County of San Francisco ("Superior Court") against PG&E Corporation and its directors, as well as against directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200 ("Section 17200"). Among other allegations, the California Attorney General alleged that past transfers of funds from the Utility to PG&E Corporation during the period from 1997 through 2000 (primarily in the form of dividends and stock repurchases), and allegedly from PG&E Corporation to other affiliates of PG&E Corporation, violated various conditions established by the CPUC in decisions approving the holding company formation. The California Attorney General alleged that the defendants violated these conditions when PG&E Corporation allegedly failed to provide adequate financial support to the Utility during the California energy crisis.

The complaint seeks injunctive relief, the appointment of a receiver, restitution in an amount according to proof, civil penalties of \$2,500 against each defendant for each violation of Section 17200, a total penalty of not less than \$500 million and costs of suit. The California Attorney General's complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150*, was filed in the Superior Court. The complaint contains some of the same allegations contained in the California Attorney General's complaint, including allegations of unfair competition in violation of Section 17200. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least \$5.2 billion from the Utility," and for unjust enrichment. The City and County of San Francisco ("CCSF") seeks injunctive relief, the appointment of a receiver, restitution, disgorgement, the imposition of a constructive trust, civil penalties of \$2,500 against each defendant for each violation of Section 17200 and costs of suit.

The complaints, which have been consolidated in the Superior Court, were filed after the CPUC issued two decisions in its investigative proceeding commenced in April 2001 into whether the California investor-owned electric utilities, including the Utility, complied with past CPUC decisions, rules and orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC would, among other matters, investigate the utilities' transfer of money to their holding companies, including during times when their utility subsidiaries were experiencing financial difficulties, the failure of the holding companies to financially assist the utilities when needed, the transfer by the holding companies of assets to unregulated subsidiaries, and the holding companies' actions to "ringfence" their unregulated subsidiaries. In May 2005, the CPUC closed this investigation without making any findings.

PG&E Corporation believes that the intercompany transactions challenged by the California Attorney General and CCSF were in full compliance with applicable law and CPUC conditions. The challenged transactions forming the bulk of the restitution claims were regular quarterly dividends and stock repurchases. As part of its annual cost of capital proceedings, the Utility advised the CPUC in advance of its forecast stock repurchases and dividends. The CPUC did not challenge or question those payments.

In January 2006, the Ninth Circuit issued a decision on the parties' appeals of various rulings by the Bankruptcy Court and the U.S. District Court for the Northern District of California concerning jurisdictional issues. The Ninth Circuit found that the Superior Court had jurisdiction over the California Attorney General's and CCSF's restitution claims. (In October 2006, the U.S. Supreme Court declined to grant PG&E Corporation's request to review the Ninth Circuit's decision.) The Ninth Circuit did not address the California Attorney General's and CCSF's underlying allegations that PG&E Corporation and the other defendants violated Section 17200. The Ninth Circuit also did not decide the issue of who would be entitled to receive the proceeds, if any, of a restitution award, and PG&E Corporation continues to believe that any such proceeds would be the property of the Utility. Pursuant to the Chapter 11 Settlement Agreement, the CPUC released all claims against PG&E Corporation or the Utility arising out of or in any way related to the energy crisis, including the CPUC's investigation into past PG&E Corporation actions during the California energy crisis. Accordingly, PG&E Corporation believes that any claims for such proceeds by the CPUC would be precluded.

While the Ninth Circuit appeal was pending, the Superior Court held a trial in December 2004 to consider the appropriate standard to determine what constitutes a separate violation of Section 17200 in order to determine the magnitude of potential penalties under Section 17200 (up to \$2,500 per separate "violation"). The Superior Court did not address the question of whether any violations occurred. In March 2005, the Superior Court issued a decision rejecting the "per victim" and "per [customer] bill" approaches advocated by the plaintiffs, standards that potentially could have resulted in millions of separate "violations." The Superior Court found that the appropriate standard was each transfer of money from the Utility to PG&E Corporation that plaintiffs allege violated Section 17200. In July 2005, the California Court of Appeal summarily denied a petition filed by the California Attorney General and CCSF seeking to overturn this decision. The next case management conference in Superior Court is scheduled on February 26, 2009.

PG&E Corporation believes that the California Attorney General's and CCSF's allegations have no merit and will continue to vigorously respond to and defend against the litigation. PG&E Corporation believes that the ultimate outcome of this matter would not result in a material adverse effect on PG&E Corporation's financial condition or results of operations.

Item 4. Submission of Matters to a Vote of Security Holders

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 20, 2009, are as follows:

Name	Age	Position
Peter A. Darbee	56	Chairman of the Board, Chief Executive Officer, and President
Kent M. Harvey	50	Senior Vice President and Chief Risk and Audit Officer
Christopher P. Johns	48	Senior Vice President, Chief Financial Officer, and Treasurer
John S. Keenan	60	Senior Vice President and Chief Operating Officer, Pacific Gas and Electric Company
Nancy E. McFadden	50	Senior Vice President, Public Affairs
Hyun Park	47	Senior Vice President and General Counsel
Greg S. Pruett	51	Senior Vice President, Corporate Relations
Rand L. Rosenberg	55	Senior Vice President, Corporate Strategy and Development
John R. Simon	44	Senior Vice President, Human Resources

All officers of PG&E Corporation serve at the pleasure of the Board of Directors. During the past five years through February 20, 2009, 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
Peter A. Darbee	Chairman of the Board, Chief Executive Officer, and President President and Chief Executive Officer, Pacific Gas and Electric Company Chairman of the Board and Chief Executive Officer Chairman of the Board, Chief Executive Officer, and President Chairman of the Board, Pacific Gas and Electric Company President and Chief Executive Officer Senior Vice President and Chief Financial Officer	September 19, 2007 to present September 5, 2008 to present July 1, 2007 to September 18, 2007 January 1, 2006 to June 30, 2007 January 1, 2006 to May 31, 2007 January 1, 2005 to December 31, 2005 September 20, 1999 to December 31, 2004
Kent M. Harvey	Senior Vice President and Chief Risk and Audit Officer Senior Vice President, Chief Financial Officer, and Treasurer, Pacific Gas and Electric Company	October 1, 2005 to present November 1, 2000 to September 30, 2005
Christopher P. Johns	Senior Vice President, Chief Financial Officer, and Treasurer Senior Vice President and Treasurer, Pacific Gas and Electric Company Senior Vice President, Chief Financial Officer, and Treasurer, Pacific Gas and Electric Company Senior Vice President, Chief Financial Officer, and Controller Senior Vice President and Controller	October 4, 2005 to present June 1, 2007 to present October 1, 2005 to May 31, 2007 January 1, 2005 to October 3, 2005 September 19, 2001 to December 31, 2004
John S. Keenan	Senior Vice President and Chief Operating Officer, Pacific Gas and Electric Company Senior Vice President, Generation and Chief Nuclear Officer, Pacific Gas and Electric Company Vice President, Fossil Generation, Progress Energy	January 1, 2008 to present December 19, 2005 to December 31, 2007 November 10, 2003 to December 18, 2005
Nancy E. McFadden	Senior Vice President, Public Affairs Senior Vice President, Public Affairs, Pacific Gas and Electric Company Vice President, Governmental Relations, Pacific Gas and Electric Company Chairperson, California Medical Assistance Commission	March 1, 2007 to present June 20, 2007 to present September 26, 2005 to February 28, 2007 November 13, 2003 to November 30, 2005
Hyun Park	Senior Vice President and General Counsel Vice President, General Counsel, and Secretary, Allegheny Energy, Inc. Senior Vice President, General Counsel, and Secretary, Sithe Energies, Inc.	November 13, 2006 to present April 5, 2005 to October 17, 2006 March 2000 to February 2005
Greg S. Pruett	Senior Vice President, Corporate Relations Vice President, Corporate Relations Vice President, Communications and Marketing, American Gas Association Chief Public Affairs Officer, Bechtel National, Inc. Vice President, Corporate Communications, PG&E Corporation	November 1, 2007 to present March 1, 2007 to October 31, 2007 April 10, 2006 to February 23, 2007 June 12, 2004 to September 12, 2005 January 1, 1998 to September 12, 2003
Rand L. Rosenberg	Senior Vice President, Corporate Strategy and Development Executive Vice President and Chief Financial Officer, Infospace, Inc.	November 1, 2005 to present September 2000 to January 20, 2001
John R. Simon	Senior Vice President, Human Resources Senior Vice President, Human Resources, Pacific Gas and Electric Company Executive Vice President, Global Human Capital, TeleTech Holdings, Inc. Senior Vice President, Human Capital, TeleTech Holdings, Inc.	April 16, 2007 to present April 16, 2007 to present March 21, 2006 to April 13, 2007 July 31, 2001 to March 20, 2006

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 20, 2009, are as follows:

Name	Age	Position
Peter A. Darbee	56	President and Chief Executive Officer
John S. Keenan	60	Senior Vice President and Chief Operating Officer
Desmond A. Bell	46	Senior Vice President, Shared Services and Chief Procurement Officer
Thomas E. Bottorff	55	Senior Vice President, Regulatory Relations
Helen A. Burt	52	Senior Vice President and Chief Customer Officer
John T. Conway	51	Senior Vice President, Generation and Chief Nuclear Officer
Christopher P. Johns	48	Senior Vice President and Treasurer
Patricia M. Lawicki	48	Senior Vice President and Chief Information Officer
Nancy E. McFadden	50	Senior Vice President, Public Affairs
Hyun Park	47	Senior Vice President and General Counsel, PG&E Corporation
Greg S. Pruett	51	Senior Vice President, Corporate Relations, PG&E Corporation
Edward A. Salas	52	Senior Vice President, Engineering and Operations
John R. Simon	44	Senior Vice President, Human Resources
Fong Wan	47	Senior Vice President, Energy Procurement
Geisha J. Williams	47	Senior Vice President, Energy Delivery
Barbara L. Barcon	52	Vice President, Finance and Chief Financial Officer

All officers of the Utility serve at the pleasure of the Board of Directors. During the past five years through February 20, 2009 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
Peter A. Darbee	President and Chief Executive Officer Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation Chairman of the Board and Chief Executive Officer, PG&E Corporation Chairman of the Board, Pacific Gas and Electric Company Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation President and Chief Executive Officer, PG&E Corporation Senior Vice President and Chief Financial Officer, PG&E Corporation	September 5, 2008 to present September 19, 2007 to present July 1, 2007 to September 18, 2007 January 1, 2006 to May 31, 2007 January 1, 2006 to June 30, 2007 January 1, 2005 to December 31, 2005 September 20, 1999 to December 31, 2004
John S. Keenan	Senior Vice President and Chief Operating Officer Senior Vice President, Generation and Chief Nuclear Officer Vice President, Fossil Generation, Progress Energy	January 1, 2008 to present December 19, 2005 to December 31, 2007 November 10, 2003 to December 18, 2005
Desmond A. Bell	Senior Vice President, Shared Services and Chief Procurement Officer Vice President, Shared Services and Chief Procurement Officer Vice President and Chief of Staff Vice President, Parts Logistics, Bombardier Aerospace	October 1, 2008 to present March 1, 2008 to September 30, 2008 March 19, 2007 to February 29, 2008 April 2003 to September 2006
Thomas E. Bottorff	Senior Vice President, Regulatory Relations Senior Vice President, Customer Service and Revenue Vice President, Customer Service	October 14, 2005 to present March 1, 2004 to October 13, 2005 June 1, 1999 to February 29, 2004
Helen A. Burt	Senior Vice President and Chief Customer Officer Management Consultant, The Burt Group	February 27, 2006 to present January 2003 to February 2006
John T. Conway	Senior Vice President, Generation and Chief Nuclear Officer Senior Vice President and Chief Nuclear Officer Site Vice President, Diablo Canyon Power Plant Site Vice President, Monticello Nuclear Plant, Nuclear Management Company Site Director, Monticello Nuclear Plant, Nuclear Management Company Vice President, Nine Mile Point, Constellation Energy Group	October 1, 2008 to present March 1, 2008 to September 30, 2008 May 20, 2007 to February 29, 2008 May 2005 to June 1, 2007 April 2004 to May 2005 November 2001 to August 2003
Christopher P. Johns	Senior Vice President and Treasurer Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation Senior Vice President, Chief Financial Officer, and Treasurer Senior Vice President, Chief Financial Officer, and Controller, PG&E Corporation Senior Vice President and Controller, PG&E Corporation	June 1, 2007 to present October 4, 2005 to present October 1, 2005 to May 31, 2007 January 1, 2005 to October 3, 2005 September 19, 2001 to December 31, 2004
Patricia M. Lawicki	Senior Vice President and Chief Information Officer Vice President and Chief Information Officer Vice President, Chief Information Officer, NiSource, Inc.	November 1, 2007 to present January 12, 2005 to October 31, 2007 April 23, 2003 to January 7, 2005
Nancy E. McFadden	Senior Vice President, Public Affairs Senior Vice President, Public Affairs, PG&E Corporation Vice President, Governmental Relations Chairperson, California Medical Assistance Commission	June 20, 2007 to present March 1, 2007 to present September 26, 2005 to February 28, 2007 November 13, 2003 to November 30, 2005
Hyun Park	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present

	Vice President, General Counsel, and Secretary, Allegheny Energy, Inc. Senior Vice President, General Counsel, and Secretary, Sithe Energies, Inc.	April 5, 2005 to October 17, 2006 March 2000 to February 2005
Greg S. Pruett	Senior Vice President, Corporate Relations, PG&E Corporation Vice President, Corporate Relations, PG&E Corporation Vice President, Communications and Marketing, American Gas Association Chief Public Affairs Officer, Bechtel National, Inc. Vice President, Corporate Communications, PG&E Corporation	November 1, 2007 to present March 1, 2007 to October 31, 2007 April 10, 2006 to February 23, 2007 June 12, 2004 to September 12, 2005 January 1, 1998 to September 12, 2003
Edward A. Salas	Senior Vice President, Engineering and Operations Staff Vice President, Network Planning, Verizon Wireless Contractor, Verizon Wireless, Local Number Portability Implementation	April 11, 2007 to present May 2004 to April 2007 May 2003 to April 2004
John R. Simon	Senior Vice President, Human Resources Senior Vice President, Human Resources, PG&E Corporation Executive Vice President, Global Human Capital, TeleTech Senior Vice President, Human Capital, TeleTech Holdings, Inc.	April 16, 2007 to present April 16, 2007 to present March 21, 2006 to April 13, 2007 July 13, 2001 to March 20, 2006
Fong Wan	Senior Vice President, Energy Procurement Vice President, Energy Procurement Vice President, Power Contracts and Electric Resource Development Vice President, Risk Initiatives, PG&E Corporation Support Services, Inc.	October 1, 2008 to present January 9, 2006 to September 30, 2008 May 1, 2004 to January 8, 2006 November 1, 2000 to April 30, 2004
Geisha J. Williams	Senior Vice President, Energy Delivery Vice President, Power Systems, Distribution, Florida Power and Light Company	December 1, 2007 to present July 2003 to July 2007
Barbara L. Barcon	Vice President, Finance and Chief Financial Officer Senior Vice President, The Gores Group - Glendon Partners Private Equity Firm Vice President, Financial Process Excellence, Northrop Grumman Corporation Vice President, Planning and Analysis, Northrop Grumman Corporation	March 24, 2008 to present 2007 to 2008 2004 to 2007 2003 to 2004

PART II

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

As of February 20, 2009, there were 85,658 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 exchanges. 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 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report. Information about the frequency and amount of dividends on common stock paid by PG&E Corporation and the Utility is set forth in the table entitled "Selected Financial Data" in the 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report. The discussion of dividends with respect to PG&E Corporation's and the Utility's common stock is set forth under the section of MD&A entitled "Liquidity and Financial Resources — Dividends" in the 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report.

During the quarter ended December 31, 2008, PG&E Corporation made equity contributions totaling \$180 million to the Utility in order to maintain the 52% common equity target authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures.

Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during 2008.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Paid 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, 2008	-	\$	-	\$
November 1 through November 30, 2008	-	\$	-	\$
December 1 through December 31, 2008	3,872 ⁽¹⁾	\$ 38.71	-	\$
Total	3,872	\$ 38.71	-	\$

⁽¹⁾ Shares tendered to satisfy tax withholding obligations arising upon the vesting of PG&E Corporation restricted stock.

During the fourth quarter of 2008, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

Item 6. Selected Financial Data

A summary of selected financial information, for each of PG&E Corporation and Pacific Gas and Electric Company for each of the last five fiscal years, is set forth under the heading “Selected Financial Data” in the 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report.

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

A discussion of PG&E Corporation's and Pacific Gas and Electric Company'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 2008 Annual Report, which discussion is incorporated by reference and included in Exhibit 13 to this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Information responding to Item 7A appears in the 2008 Annual Report under the heading “Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Management Activities,” and under Notes 2, 11 and 12 of the Notes to the Consolidated Financial Statements of the 2008 Annual Report, which information is incorporated by reference and included in Exhibit 13 to this report.

Item 8. Financial Statements and Supplementary Data

Information responding to Item 8 appears in the 2008 Annual Report under the following headings for PG&E Corporation: “Consolidated Statements of Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity;” under the following headings for Pacific Gas and Electric Company: “Consolidated Statements of Income,” “Consolidated Balance Sheets,” “Consolidated Statements of Cash Flows,” and “Consolidated Statements of Shareholders' Equity;” 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 “Report of Independent Registered Public Accounting Firm,” which information is incorporated by reference and included in Exhibit 13 to this report.

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, 2008, 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 Securities Exchange Act of 1934 ("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, 2008 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 2008 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

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included above in a separate item captioned "Executive Officers of the Registrants" at the end of Part I of this report. Other information responding to Item 10 is included under the heading "Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" and under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated 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 Pacific Gas and Electric Company's website, www.pge.com: (1) the codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company 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 Pacific Gas and Electric Company'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. Shareholders also may obtain print copies of these documents by submitting a written request to Linda Y.H. Cheng, Vice President, Corporate Governance and Corporate Secretary of PG&E Corporation and Pacific Gas and Electric Company, One Market, Spear Tower, Suite 2400, San Francisco, California 94105.

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 Pacific Gas and Electric Company 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 4 business days of the waiver.

Procedures for Shareholder Recommendations of Nominees to the Boards of Directors

During 2008 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy

Statement relating to the 2008 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or the Utility'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 included under the heading "Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company — Board Committees — Audit Committees" in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 11. Executive Compensation

Information responding to Item 11, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2008," "Grants of Plan-based Awards in 2008," "Outstanding Equity Awards at Fiscal Year End - 2008," "Option Exercises and Stock Vested During 2008," "Pension Benefits - 2008," "Non-Qualified Deferred Compensation," "Compensation of Non-Employee Directors," and "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

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

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Security Ownership of Management" and under the heading "Principal Shareholders" in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2008 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	3,062,874 ⁽¹⁾	\$23.45	10,342,381 ⁽²⁾
Equity compensation plans not approved by shareholders	—	—	—
Total equity compensation plans	3,062,874 ⁽¹⁾	\$23.45	10,342,381 ⁽²⁾

(1) Includes 94,613 phantom stock units and restricted stock units. The weighted average exercise price reported in column (b) does not take these awards into account.

(2) Represents the total number of shares available for issuance under the PG&E Corporation's Long-Term Incentive Program ("LTIP") and the PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP") as of December 31, 2008. 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, and phantom stock. For a description of the LTIP and the 2006 LTIP, see Note 14 of the Notes to the Consolidated Financial Statements in the 2008 Annual Report.

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

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the headings "Related Person Transactions," "Review, Approval, and Ratification of Related Person Transactions" and "Information Regarding the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company — Director Independence" in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 14. Principal Accountant Fees and Services

Information responding to Item 14, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading “Information Regarding the Independent Registered Public Accounting Firm of PG&E Corporation and Pacific Gas and Electric Company” in the Joint Proxy Statement relating to the 2009 Annual Meetings of Shareholders, which information is hereby incorporated 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 2008 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2008, 2007, and 2006 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2008 and 2007 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2007, and 2006 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2008, 2007, and 2006 for each of PG&E Corporation and Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Report 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:

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

I—Condensed Financial Information of Parent as of December 31, 2008 and 2007 and for the Years Ended December 31, 2008, 2007, and 2006.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2008, 2007, and 2006.

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 Quarterly Report on 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 January 1, 2009
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 January 1, 2009
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 filed May 4, 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 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 Current Report on 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 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 Current Report on 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 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 Current Report on 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 Current Report on Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)
- 4.6 Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).
- 4.7 Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
- 10.1 Amended and Restated Unsecured Revolving Credit Agreement entered into among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JPMorgan Securities Inc., as syndication agent, Barclays Bank Plc and BNP Paribas, as documentation agents and lenders, Deutsche Bank Securities Inc., as documentation agent, and other lenders, dated February 26, 2007 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
- 10.2 Amended and Restated Unsecured Revolving Credit Agreement entered into among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities Inc., as syndication agent, ABN AMRO Bank, N.V., Bank of America, N.A., and Barclays Bank Plc, as documentation agents and lenders, and other lenders, dated February 26, 2007 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
- 10.3 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)
- 10.4 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)
- 10.5 Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
- *10.6 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)
- *10.7 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)
- *10.8 Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective July 1, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)
- *10.9 Restricted Stock Award Agreement between PG&E Corporation and Peter A. Darbee dated January 3, 2007 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.3)
- *10.10 Amendment to January 3, 2007 Restricted Stock Agreement between PG&E Corporation and Peter A. Darbee, effective May 9, 2008 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12609), Exhibit 10.1)
- *10.11 Amended and Restated Restricted Stock Unit Agreement between Peter A. Darbee and PG&E Corporation (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009)
- *10.12 Restricted Stock Unit Agreement between Peter A. Darbee and PG&E Corporation dated January 2, 2009
- *10.13 Letter regarding Compensation Arrangement between Pacific Gas and Electric Company and William T. Morrow dated June 20, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.1)
- *10.14 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated January 29, 2007 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609), Exhibit 10.4)
- *10.15 Performance Share Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.13)
- *10.16 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.14)
- *10.17 Separation Agreement between William T. Morrow and Pacific Gas and Electric Company dated July 8, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12609), Exhibit 10)
- *10.18 Letter regarding Compensation Arrangement between PG&E Corporation and Rand L. Rosenberg dated October 19, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-12609), Exhibit 10.18)
- *10.19 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)
- *10.20 Letter regarding Compensation Agreement between PG&E Corporation and G. Robert Powell dated August 8, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.17)
- *10.21 Letter regarding Compensation Agreement between Pacific Gas and Electric Company and John S. Keenan dated November 21, 2005
- *10.22 Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Barbara Barcon dated March 3, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12609), Exhibit 10.3)
- *10.23 Separation Agreement between PG&E Corporation and G. Robert Powell dated March 6, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12609), Exhibit 10.4)
- *10.24 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009)
- *10.25 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007 (File No. 1-12609), Exhibit 10.19)
- *10.26 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2009
- *10.27 Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.28 Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009

- (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.29 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2009 (amended to comply with Internal Revenue Code Section 409A Regulations)
- *10.30 Pacific Gas and Electric Company Relocation Assistance Program for Officers
- *10.31 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)
- *10.32 Amendment to Postretirement Life Insurance Plan of the Pacific Gas and Electric Company dated December 30, 2008 (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.33 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)
- *10.34 Resolution of the PG&E Corporation Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.28)
- *10.35 Resolution of the Pacific Gas and Electric Company Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.29)
- *10.36 Resolution of the PG&E Corporation Board of Directors dated September 17, 2008, adopting director compensation arrangement effective January 1, 2009
- *10.37 Resolution of the Pacific Gas and Electric Company Board of Directors dated September 17, 2008, adopting director compensation arrangement effective January 1, 2009
- *10.38 PG&E Corporation 2006 Long-Term Incentive Plan, as amended through February 18, 2009
- *10.39 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 Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
- *10.40 Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)
- *10.41 Form of Restricted Stock Agreement for 2005 grants 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. 12609 and File No. 1-2348), Exhibit 99.3)
- *10.42 Form of Restricted Stock Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.1)
- *10.43 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)
- *10.44 Form of Restricted Stock Agreement for 2008 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, 2008 (File No. 1-12609), Exhibit 10.5)
- *10.45 Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (amendments to comply with Internal Revenue Code Section 409A Regulations)
- *10.46 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. 12609 and File No. 1-2348), Exhibit 99.1)
- *10.47 Form of Performance Share Agreement for 2005 grants 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. 12609 and File No. 1-2348), Exhibit 99.2)
- *10.48 Form of Performance Share Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.2)
- *10.49 Form of Performance Share 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 10.44)
- *10.50 Form of Performance Share Agreement for 2008 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, 2008 (File No. 1-12609), Exhibit 10.6)
- *10.51 Form of Amended and Restated Performance Share Agreement for 2006 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
- *10.52 Form of Amended and Restated Performance Share Agreement for 2007 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
- *10.53 Form of Amended and Restated Performance Share Agreement for 2008 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
- *10.54 PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective February 17, 2009
- *10.55 PG&E Corporation Officer Severance Policy, as amended 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 10.48)
- *10.56 PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2009 (amended to comply with Internal Revenue Code Section 409A regulations)
- *10.57 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)
- *10.58 Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations)
- *10.59 PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
- *10.60 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)
- *10.61 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)
- *10.62 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)
11	Computation of Earnings Per Common Share
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
13	The following portions of the 2008 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 Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of 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)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	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
*	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, 2008 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION
(Registrant)

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)

By: *PETER A. DARBEE
 Peter A. Darbee
 Chairman of the Board, Chief Executive Officer,
 and President
 Date: February 24, 2009

By: *PETER A. DARBEE
 Peter A. Darbee
 President and Chief Executive Officer
 Date: February 24, 2009

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

Signature	Title	Date
A. Principal Executive Officers		
<u>*PETER A. DARBEE</u> Peter A. Darbee	Chairman of the Board, Chief Executive Officer, President, and Director (PG&E Corporation)	February 24, 2009
	President and Chief Executive Officer (Pacific Gas and Electric Company)	
B. Principal Financial Officers		
<u>*CHRISTOPHER P. JOHNS</u> Christopher P. Johns	Senior Vice President, Chief Financial Officer, and Treasurer (PG&E Corporation)	February 24, 2009
<u>*BARBARA L. BARCON</u> Barbara L. Barcon	Vice President, Finance and Chief Financial Officer (Pacific Gas and Electric Company)	February 24, 2009
C. Principal Accounting Officer		
<u>*STEPHEN J. CAIRNS</u> *Stephen J. Cairns	Vice President and Controller (PG&E Corporation and (Pacific Gas and Electric Company)	February 24, 2009
D. Directors		
<u>*DAVID R. ANDREWS</u> David R. Andrews	Director	February 24, 2009
<u>*C. LEE COX</u> C. Lee Cox	Director	February 24, 2009
<u>*MARYELLEN C. HERRINGER</u> Maryellen C. Herringer	Director	February 24, 2009
<u>*ROGER H. KIMMEL</u> Roger H. Kimmel	Director	February 24, 2009
<u>*RICHARD A. MESERVE</u> Richard A. Meserve	Director	February 24, 2009
<u>*MARY S. METZ</u> Mary S. Metz	Director	February 24, 2009
<u>*FORREST E. MILLER</u> Forrest E. Miller	Director	February 24, 2009
<u>*BARBARA L. RAMBO</u> Barbara L. Rambo	Director	February 24, 2009
<u>*BARRY LAWSON WILLIAMS</u> Barry Lawson Williams	Director	February 24, 2009
<u>*By: HYUN PARK</u> HYUN PARK, Attorney-in-Fact		

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the “Company”) and Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and the Company’s and the Utility’s internal control over financial reporting as of December 31, 2008, and have issued our report thereon dated February 19, 2009 (which expresses an unqualified opinion and includes for the Company and Utility an explanatory paragraph stating that in January 2008 new accounting standards were adopted for addressing fair value measurement and an amendment to an interpretation of accounting standards for offsetting amounts related to certain contracts, in 2007 a new interpretation of accounting standards for uncertainty in income taxes, and in 2006 new accounting standards for defined benefit pensions and other postretirement plans and share-based payments); such consolidated financial statements and our report are included in your 2008 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(a)2. 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.

DELOITTE & TOUCHE LLP

February 19, 2009
San Francisco, CA

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

	Year Ended December 31,		
	2008	2007	2006
Administrative service revenue	119	102	110
Equity in earnings of subsidiaries	1,182	1,006	964
Operating expenses	(105)	(112)	(115)
Interest income	4	15	15
Interest expense	(30)	(31)	(30)
Other income (expense)	(46)	(6)	(1)
Income before income taxes	1,124	974	943
Income tax benefit	60	32	48
Income from continuing operations	1,184	1,006	991
Gain on disposal of NEGТ	154	-	-
Net income before intercompany eliminations	1,338	1,006	991
Weighted average common shares outstanding, basic	357	351	346
Weighted average common shares outstanding, diluted	358	353	349
Earnings per common share, basic ⁽¹⁾	\$3.64	\$2.79	\$2.78
Earnings per common share, diluted ⁽¹⁾	\$3.63	\$2.78	\$2.76

⁽¹⁾ PG&E Corporation adopted the consensus reached by Emerging Issues Task Force, or EITF, in EITF issue No. 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128," or EITF 03-06, as ratified by the Financial Accounting Standards Board on March 31, 2004.

PG&E Corporation currently has outstanding \$280 million principal amount of convertible subordinated 9.50% notes due 2010, or Convertible Notes, that are entitled to receive (non-cumulative) dividend payments without exercising the conversion option. These Convertible Notes, which were issued in June 2002, meet the criteria of a participating security in the calculation of earnings per share using the "two-class" method.

Accordingly, the basic and diluted earnings per share calculations for each of the years in the three year period ended December 31, 2008 reflect the allocation of earnings between PG&E Corporation common stock and the participating security.

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

	Balance at December 31,	
	2008	2007
ASSETS		
Current Assets :		
Cash and cash equivalents	\$ 167	\$ 204
Advances to affiliates	28	30
Income taxes receivable	148	46
Other current assets	14	3
Total current assets	357	283
Equipment	17	17
Accumulated depreciation	(15)	(15)
Net equipment	2	2
Investments in subsidiaries	9,539	8,886
Other investments	68	87
Deferred income taxes	51	51
Other	4	9
Total Assets	\$ 10,021	\$ 9,318
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable—related parties	\$ 34	\$ 40
Accounts payable—other	18	24
Other	189	174
Total current liabilities	241	238
Noncurrent Liabilities:		
Long-term debt	280	280
Income taxes payable	23	131
Other	100	116
Total noncurrent liabilities	403	527
Common Shareholders' Equity		
Common stock	5,984	6,110
Common stock held by subsidiary	-	(718)
Reinvested earnings	3,614	3,151
Accumulated other comprehensive income	(221)	10
Total common shareholders' equity	9,377	8,553
Total Liabilities and Shareholders' Equity	\$ 10,021	\$ 9,318

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

	Year Ended December 31,		
	2008	2007	2006
Cash Flows from Operating Activities:			
Net income	\$ 1,338	\$ 1,006	\$ 991
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	3	1	-
Equity in earnings of subsidiaries	(1,180)	(1,006)	(964)
Noncurrent income taxes receivable/payable	(108)	4	-
	(81)	(19)	
Other	()	()	132
Net cash used in operating activities	(28)	24	159
Cash Flows From Investing Activities:			
Capital expenditures	-	(1)	(1)
Investment in subsidiaries	(275)	(405)	-
Dividends received from subsidiaries	596	509	460
Other	(12)	-	-
Net cash provided by investing activities	309	103	459
Cash Flows From Financing Activities ⁽¹⁾ :			
Common stock issued	225	175	131
Common stock repurchased	-	-	(114)
Common stock dividends paid	(546)	(496)	(456)
Other	2	12	(43)
Net cash used in financing activities	(319)	(309)	(482)
Net change in cash and cash equivalents	(38)	(182)	136
Cash and cash equivalents at January 1	204	386	250
	\$ 166	\$ 204	\$ 386
Cash and cash equivalents at December 31			

⁽¹⁾ On January 15, 2008, PG&E Corporation paid a quarterly common stock dividend of \$0.36 per share. On April 15, July 15, and October 15, 2008, PG&E Corporation paid quarterly common stock dividends of \$0.39 per share. Of the total dividend payments made by PG&E Corporation in 2008, approximately \$28 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

On January 15, 2007, PG&E Corporation paid a quarterly common stock dividend of \$0.33 per share. On April 15, July 15, and October 15, 2007, PG&E Corporation paid quarterly common stock dividends of \$0.36 per share. Of the total dividend payments made by PG&E Corporation in 2007, approximately \$35 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

On January 16, April 15, July 15, and October 15, 2006, PG&E Corporation paid a quarterly common stock dividend of \$0.33 per share, totaling approximately \$489 million. Of the total dividend payments made by PG&E Corporation in 2006, approximately \$33 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

PG&E Corporation

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2008, 2007, and 2006

Description	Balance at Beginning of Period	Additions		Deductions ⁽³⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2008:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 58	\$ 68	\$ 11	\$ 61	\$ 76
2007:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 50	\$ 20	\$ -	\$ 12	\$ 58
2006:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 77	\$ 2	\$ -	\$ 29	\$ 50

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

⁽²⁾ Allowance for uncollectible accounts does not include NEGT.

⁽³⁾ 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, 2008, 2007, and 2006

Description	Balance at Beginning of Period	Additions		Deductions ⁽²⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2008:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 58	\$ 68	\$ 11	\$ 61	\$ 76
2007:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 50	\$ 20	\$ -	\$ 12	\$ 58
2006:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 77	\$ 2	\$ -	\$ 29	\$ 50

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

⁽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 Quarterly Report on 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 January 1, 2009
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 January 1, 2009
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 filed May 4, 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 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 Current Report on 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 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 Current Report on 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 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 Current Report on 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 Current Report on Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1)
4.6	Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).
4.7	Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
10.1	Amended and Restated Unsecured Revolving Credit Agreement entered into among Pacific Gas and Electric Company, Citicorp North America, Inc., as administrative agent and a lender, JPMorgan Securities Inc., as syndication agent, Barclays Bank Plc and BNP Paribas, as documentation agents and lenders, Deutsche Bank Securities Inc., as documentation agent, and other lenders, dated February 26, 2007 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
10.2	Amended and Restated Unsecured Revolving Credit Agreement entered into among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities Inc., as syndication agent, ABN AMRO Bank, N.V., Bank of America, N.A., and Barclays Bank Plc, as documentation agents and lenders, and other lenders, dated February 26, 2007 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2)
10.3	Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)
10.4	Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8)
10.5	Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.9)
*10.6	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)
*10.7	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)
*10.8	Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective July 1, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)
*10.9	Restricted Stock Award Agreement between PG&E Corporation and Peter A. Darbee dated January 3, 2007 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.3)
*10.10	Amendment to January 3, 2007 Restricted Stock Agreement between PG&E Corporation and Peter A. Darbee, effective May 9, 2008 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12609), Exhibit 10.1)
*10.11	Amended and Restated Restricted Stock Unit Agreement between Peter A. Darbee and PG&E Corporation (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009)
*10.12	Restricted Stock Unit Agreement between Peter A. Darbee and PG&E Corporation dated January 2, 2009

- *10.13 Letter regarding Compensation Arrangement between Pacific Gas and Electric Company and William T. Morrow dated June 20, 2006 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-12609), Exhibit 10.1)
- *10.14 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated January 29, 2007 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 1-12609), Exhibit 10.4)
- *10.15 Performance Share Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.13)
- *10.16 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.14)
- *10.17 Separation Agreement between William T. Morrow and Pacific Gas and Electric Company dated July 8, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12609), Exhibit 10)
- *10.18 Letter regarding Compensation Arrangement between PG&E Corporation and Rand L. Rosenberg dated October 19, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-12609), Exhibit 10.18)
- *10.19 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)
- *10.20 Letter regarding Compensation Agreement between PG&E Corporation and G. Robert Powell dated August 8, 2005 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007) (File No. 1-12609), Exhibit 10.17)
- *10.21 Letter regarding Compensation Agreement between Pacific Gas and Electric Company and John S. Keenan dated November 21, 2005
- *10.22 Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Barbara Barcon dated March 3, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12609), Exhibit 10.3)
- *10.23 Separation Agreement between PG&E Corporation and G. Robert Powell dated March 6, 2008 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12609), Exhibit 10.4)
- *10.24 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009)
- *10.25 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2008 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2007 (File No. 1-12609), Exhibit 10.19)
- *10.26 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2009
- *10.27 Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.28 Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.29 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2009 (amended to comply with Internal Revenue Code Section 409A Regulations)
- *10.30 Pacific Gas and Electric Company Relocation Assistance Program for Officers
- *10.31 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)
- *10.32 Amendment to Postretirement Life Insurance Plan of the Pacific Gas and Electric Company dated December 30, 2008 (amendment to comply with Internal Revenue Code Section 409A regulations)
- *10.33 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004) (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.27)
- *10.34 Resolution of the PG&E Corporation Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.28)
- *10.35 Resolution of the Pacific Gas and Electric Company Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-K for the year ended December 31, 2007 (File No. 1-12609 and File No. 12348), Exhibit 10.29)
- *10.36 Resolution of the PG&E Corporation Board of Directors dated September 17, 2008, adopting director compensation arrangement effective January 1, 2009
- *10.37 Resolution of the Pacific Gas and Electric Company Board of Directors dated September 17, 2008, adopting director compensation arrangement effective January 1, 2009
- *10.38 PG&E Corporation 2006 Long-Term Incentive Plan, as amended through February 18, 2009
- *10.39 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 Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
- *10.40 Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)
- *10.41 Form of Restricted Stock Agreement for 2005 grants 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. 12609 and File No. 1-2348), Exhibit 99.3)
- *10.42 Form of Restricted Stock Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.1)
- *10.43 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)
- *10.44 Form of Restricted Stock Agreement for 2008 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, 2008 (File No. 1-12609), Exhibit 10.5)
- *10.45 Form of Amendment to Restricted Stock Agreements for grants made between January 2005 and March 2008 (amendments to comply with Internal Revenue Code Section 409A Regulations)
- *10.46 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. 12609 and File No. 1-2348), Exhibit 99.1)
- *10.47 Form of Performance Share Agreement for 2005 grants 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. 12609 and File No. 1-

	2348), Exhibit 99.2)
*10.48	Form of Performance Share Agreement for 2006 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 9, 2006, Exhibit 99.2)
*10.49	Form of Performance Share 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 10.44)
*10.50	Form of Performance Share Agreement for 2008 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, 2008 (File No. 1-12609), Exhibit 10.6)
*10.51	Form of Amended and Restated Performance Share Agreement for 2006 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
*10.52	Form of Amended and Restated Performance Share Agreement for 2007 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
*10.53	Form of Amended and Restated Performance Share Agreement for 2008 grants (amendments to comply with Internal Revenue Code Section 409A Regulations)
*10.54	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective February 17, 2009
*10.55	PG&E Corporation Officer Severance Policy, as amended 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 10.48)
*10.56	PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2009 (amended to comply with Internal Revenue Code Section 409A regulations)
*10.57	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)
*10.58	Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations)
*10.59	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.60	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)
*10.61	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)
*10.62	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)
11	Computation of Earnings Per Common Share
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
13	The following portions of the 2008 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 Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of 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)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	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
*	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.

**Bylaws
of
PG&E Corporation**
amended as of January 1, 2009

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting** . All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings** . The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day

following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings** . Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President, or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings** . At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **Shareholder Action by Written Consent.** Subject to Section 603 of the California Corporations Code, any action which, under any provision of the California Corporations Code, may be taken at any annual or special meeting of shareholders may be taken without a meeting and without prior notice if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Any party seeking to solicit written consent from shareholders to take corporate action must deliver a notice to the Corporate Secretary of the Corporation which requests the Board of Directors to set a record date for determining shareholders entitled to give such consent. Such written request must set forth as to each matter the party proposes for shareholder action by written consents (a) a brief description of the matter and (b) the class and number of shares of the Corporation that are beneficially owned by the requesting party. Within ten days of receiving the request in the proper form, the Board shall set a record date for the taking of such action by written consent in accordance with California Corporations Code Section 701 and Article IV, Section 1 of these Bylaws. If the Board fails to set a record date within such ten-day period, the record date for determining shareholders entitled to give the written consent for the matters specified in the notice shall be the day on which the first written consent is given in accordance with California Corporations Code Section 701.

Each written consent delivered to the Corporation must set forth (a) the action sought to be taken, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, (d) the name and address of the proxyholder authorized by the shareholder to give such written consent, if applicable, and (d) any material interest of the shareholder or proxyholder in the action sought to be taken.

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in opposition to action by consent proposed by the Corporation (the "Soliciting Shareholders"), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

Within three business days after receipt of the earliest dated consent solicited by the Soliciting Shareholders and delivered to the Corporation in the manner provided in California Corporations Code Section 603 or the determination by the Board of Directors of the Corporation that the Corporation should seek corporate action by written consent, as the case may be, the Corporate Secretary shall engage nationally recognized independent inspectors of elections for the purpose of performing a ministerial review of the validity of the consents and revocations. The cost of retaining inspectors of election shall be borne by the Corporation.

Consents and revocations shall be delivered to the inspectors upon receipt by the Corporation, the Soliciting Shareholders or their proxy solicitors, or other designated agents. As soon as consents and revocations are received, the inspectors shall review the consents and revocations and shall maintain a count of the number of valid and unrevoked consents. The inspectors shall keep such count confidential and shall not reveal the count to the Corporation, the Soliciting Shareholder or their representatives, or any other entity. As soon as practicable after the earlier of (i) sixty days after the date of the earliest dated consent delivered to the Corporation in the manner provided in California Corporations Code Section 603, or (ii) a written request therefor by the Corporation or the Soliciting Shareholders (whichever is soliciting consents), notice of which request shall be given to the party opposing the solicitation of consents, if any, which request shall state that the Corporation or Soliciting Shareholders, as the case may be, have a good faith belief that the requisite number of valid and unrevoked consents to authorize or take the action specified in the consents has been received in accordance with these Bylaws, the inspectors shall issue a preliminary report to the Corporation and the Soliciting Shareholders stating: (a) the number of valid consents, (b) the number of valid revocations, (c) the number of valid and unrevoked consents, (d) the number of invalid consents, (e) the number of invalid revocations, and (f) whether, based on their preliminary count, the requisite number of valid and unrevoked consents has been obtained to authorize or take the action specified in the consents.

Unless the Corporation and the Soliciting Shareholders shall agree to a shorter or longer period, the Corporation and the Soliciting Shareholders shall have forty-eight hours to review the consents and revocations and to advise the inspectors and the opposing party in writing as to whether they intend to challenge the preliminary report of the inspectors. If no written notice of an intention to challenge the preliminary report is received within forty-eight hours after the inspectors' issuance of the preliminary report, the inspectors shall issue to the Corporation and the Soliciting Shareholders their final report containing the information from the inspectors' determination with respect to whether the requisite number of valid and unrevoked consents was obtained to authorize and take the action specified in the consents. If the Corporation or the Soliciting Shareholders issue written notice of an intention to challenge the inspectors' preliminary report within forty-eight hours after the issuance of that report, a challenge session shall be scheduled by the inspectors as promptly as practicable. A transcript of the challenge session shall be recorded by a certified court reporter. Following completion of the challenge session, the inspectors shall as promptly as practicable issue their final report to the Soliciting Shareholders and the Corporation, which report shall contain the information included in the preliminary report, plus all changes in the vote totals as a result of the challenge and a certification of whether the requisite number of valid and unrevoked consents was obtained to authorize or take the action specified in the consents. A copy of the final report of the inspectors shall be included in the book in which the proceedings of meetings of shareholders are recorded.

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with California Corporations Code Section 603 of the results of any consent solicitation or

the taking of the corporate action without a meeting and by less than unanimous written consent.

Article II. DIRECTORS.

1. **Number** . As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers** . The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees** . The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings** . Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, the Chief Executive Officer, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings** . The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate

messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum** . A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent** . Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone** . Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

9. **Majority Voting**. In any uncontested election, nominees receiving the affirmative vote of a majority of the shares represented and voting at a duly held meeting at which a quorum is present (which shares voting affirmatively also constitute at least a majority of the required quorum) shall be elected. In any election that is not an uncontested election, the nominees receiving the highest number of affirmative votes of the shares entitled to be voted for them, up to the number of directors to be elected by those shares, shall be elected; votes against a director and votes withheld shall have no legal effect.

For purposes of these Bylaws, “uncontested election” means an election of directors of the Corporation in which, at the expiration of the times fixed under Article I, Section 2 of these Bylaws requiring advance notification of director nominees, or for special meetings, at the time notice is given of the meeting at which the election is to occur, the number of nominees for election does not exceed the number of directors to be elected by the shareholders at that election.

If an incumbent director fails, in an uncontested election, to receive the vote required to be elected in accordance with this Article II, Section 9, then, unless the incumbent director has earlier resigned, the term of such incumbent director shall end on the date that is the earlier of (a) ninety (90) days after the date on which the voting results are determined pursuant to Section 707 of the California Corporations Code, or (b) the date on which the Board of Directors selects a person to fill the office held by that director in accordance with the procedures set forth in these Bylaws and Section 305 of the California Corporations Code.

**Article III.
OFFICERS.**

1. **Officers** . The officers of the Corporation shall be elected by the Board of Directors and include a President, a Corporate Secretary, a Treasurer, or other such officers as required by law. The Board of Directors also may elect one or more Vice Presidents, Assistant Secretaries, Assistant Treasurers, and other such officers as may be appropriate, including the offices described below. Any number of offices may be held by the same person.

2. **Chairman of the Board** . The Chairman of the Board shall be a member of the Board of Directors and preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and, in the absence or disability of the Chief Executive Officer, shall exercise the Chief Executive Officer's duties and responsibilities.

3. **Vice Chairman of the Board** . The Vice Chairman of the Board shall be a member of the Board of Directors and have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee** . The Chairman of the Executive Committee shall be a member of the Board of Directors and preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **Chief Executive Officer**. The Chief Executive Officer shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. If there be no Chairman of the Board, the Chief Executive Officer shall also exercise the duties and responsibilities of that office. The Chief Executive Officer shall have authority to sign on behalf of the Corporation agreements and instruments of every character. In the absence or disability of the President, the Chief Executive Officer shall exercise the President's duties and responsibilities.

6. **President** . The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the Bylaws. If there be no Chief Executive Officer, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

7. **Chief Financial Officer** . The Chief Financial Officer shall be responsible for the overall management of the financial affairs of the Corporation. The Chief Financial Officer shall render a statement of the Corporation's financial condition and an account of all transactions whenever requested by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, or the President.

The Chief Financial Officer shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

8. **General Counsel** . The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

9. **Vice Presidents** . Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, or the President may confer a special title upon any Vice President.

10. **Corporate Secretary** . The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the

seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

11. **Treasurer** . The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Bylaws.

The Assistant Treasurers shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

12. **Controller** . The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV.
MISCELLANEOUS.

1. **Record Date** . The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Certificates; Direct Registration System** . Shares of the Corporation's capital stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation's capital stock may also be evidenced by registration in the holder's name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the New York Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates** . Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate (or uncertificated shares in lieu of a new certificate) may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

**Article V.
AMENDMENTS.**

1. **Amendment by Shareholders** . Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors** . To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors; provided, however, that amendments to Article II, Section 9 of these Bylaws, and any other Bylaw provision that implements a majority voting standard for director elections (excepting any amendments intended to conform those Bylaw provisions to changes in applicable laws) shall be amended by the shareholders of the Corporation as provided in Section 1 of this Article V.

Bylaws
of
Pacific Gas and Electric Company
amended as of January 1, 2009

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting.** All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings.** The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day

following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings.** Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings.** At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **No Cumulative Voting.** No shareholder of the Corporation shall be entitled to cumulate his or her voting power.

Article II. DIRECTORS.

1. **Number.** The Board of Directors of this Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.
2. **Powers.** The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.
3. **Committees.** The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.
4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, the Chief Executive Officer, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.
5. **Special Meetings.** The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the Chief Executive Officer, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at

least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum.** A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent.** Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone.** Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

9. **Majority Voting.** In any uncontested election, nominees receiving the affirmative vote of a majority of the shares represented and voting at a duly held meeting at which a quorum is present (which shares voting affirmatively also constitute at least a majority of the required quorum) shall be elected. In any election that is not an uncontested election, the nominees receiving the highest number of affirmative votes of the shares entitled to be voted for them, up to the number of directors to be elected by those shares, shall be elected; votes against a director and votes withheld shall have no legal effect.

For purposes of these Bylaws, “uncontested election” means an election of directors of the Corporation in which, at the expiration of the times fixed under Article I, Section 2 of these Bylaws requiring advance notification of director nominees, or for special meetings, at the time notice is given of the meeting at which the election is to occur, the number of nominees for election does not exceed the number of directors to be elected by the shareholders at that election.

If an incumbent director fails, in an uncontested election, to receive the vote required to be elected in accordance with this Article II, Section 9, then, unless the incumbent director has earlier resigned, the term of such incumbent director shall end on the date that is the earlier of (a) ninety (90) days after the date on which the voting results are determined pursuant to Section 707 of the California Corporations Code, or (b) the date on which the Board of Directors selects a person to fill the office held by that director in accordance with the procedures set forth in these Bylaws and Section 305 of the California Corporations Code.

10. **Certain Powers Reserved to the Shareholders.** So long as PG&E Corporation shall hold the majority of the outstanding shares of the Corporation, PG&E Corporation may require the written consent of the PG&E Corporation Chairman of the Board or the PG&E Corporation Chief Executive Officer to enter into and execute any

transaction or type of transaction identified by the Board of Directors of PG&E Corporation as a “Designated Transaction.” For purposes of this Section 10, a Designated Transaction shall be any transaction or type of transaction identified in a duly adopted resolution of the Board of Directors of PG&E Corporation as requiring the written consent of the PG&E Corporation Chairman of the Board or the PG&E Corporation Chief Executive Officer pursuant to this Section 10. Notwithstanding the foregoing, nothing in this Section 10 shall limit the power of the Corporation to enter into or execute any transaction or type of transaction prior to the receipt by the Corporate Secretary of the Corporation of the resolution designating such transaction or type of transaction as a Designated Transaction pursuant to this Section 10.

Article III. OFFICERS.

1. **Officers.** The officers of the Corporation shall be elected by the Board of Directors and include a President, a Corporate Secretary, a Treasurer or other such officers as required by law. The Board of Directors also may elect one or more Vice Presidents, Assistant Secretaries, Assistant Treasurers, and such other officers as may be appropriate, including the offices described below. Any number of offices may be held by the same person.

2. **Chairman of the Board.** The Chairman of the Board shall be a member of the Board of Directors and preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and in the absence or disability of the Chief Executive Officer, shall exercise the Chief Executive Officer’s duties and responsibilities.

3. **Vice Chairman of the Board.** The Vice Chairman of the Board shall be a member of the Board of Directors and have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, The Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee.** The Chairman of the Executive Committee shall be a member of the Board of Directors and preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and

assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **Chief Executive Officer.** The Chief Executive Officer shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. If there be no Chairman of the Board, the Chief Executive Officer shall also exercise the duties and responsibilities of that office. The Chief Executive Officer shall have authority to sign on behalf of the Corporation agreements and instruments of every character. In the absence or disability of the President, the Chief Executive Officer shall exercise the President's duties and responsibilities.

6. **President.** The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the Bylaws. If there be no Chief Executive Officer, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

7. **Vice Presidents.** Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors of this company, the Chairman of the Board of this company, the Vice Chairman of the Board of this company, or the Chief Executive Officer of PG&E Corporation may confer a special title upon any Vice President.

8. **Corporate Secretary.** The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

9. **Treasurer.** The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

The Assistant Treasurer shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

10. **General Counsel.** The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws.

11. **Controller.** The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chief Executive Officer, the President, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV.
MISCELLANEOUS.

1. **Record Date.** The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Certificates; Direct Registration System.** Shares of the Corporation's stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation's capital stock may also be evidenced by registration in the holder's name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the American Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation only after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates.** Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board

of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate (or uncertificated shares in lieu of a new certificate) may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

**Article V.
AMENDMENTS.**

1. **Amendment by Shareholders.** Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.
2. **Amendment by Directors.** To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors; provided, however, that amendments to Article II, Sections 9 and 10 of these Bylaws, and any other Bylaw provision that implements a majority voting standard for director elections (excepting any amendments intended to conform those Bylaw provisions to changes in applicable laws) shall be amended by the shareholders of the Corporation as provided in Section 1 of this Article V.

PG&E CORPORATION
2005 SUPPLEMENTAL RETIREMENT SAVINGS PLAN

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PG&E CORPORATION

2005 SUPPLEMENTAL RETIREMENT SAVINGS PLAN

This is the controlling and definitive statement of the PG&E CORPORATION (“PG&E CORP”) 2005 Supplemental Retirement Savings Plan (the “Plan”). The Plan was amended for compliance with the final Code Section 409A regulations effective as of January 1, 2009. Except as provided herein, the Plan is generally effective as of January 1, 2005, with respect to all individuals who are Eligible Employees as of such date. The Plan continues the benefit program embodied in the PG&E Corporation Supplemental Retirement Savings Plan (the “Prior Plan”). Benefits accrued under the Prior Plan continue to be payable under the Prior Plan pursuant to the terms and conditions of the Prior Plan.

1. Purpose of the Plan. The Plan is established and is maintained for the benefit of a select group of management and highly compensated employees of PG&E CORP and its Participating Subsidiaries in order to provide such employees with certain deferred compensation benefits. The Plan is an unfunded deferred compensation plan that is intended to qualify for the exemptions provided in Sections 201, 301, and 401 of ERISA.

2. Definitions. The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:

(a) “Basic Employer Contributions” shall mean the amounts credited to Eligible Employees’ Accounts under the Plan by the Employers, in accordance with Section 3(c).

(b) “Board of Directors” shall mean the Board of Directors of PG&E CORP, as from time to time constituted.

(c) “Code” shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.

(d) “Committee” shall mean the Nominating, Compensation and Governance Committee of the Board, as it may be constituted from time to time.

(e) “Eligible Employee” shall mean an Employee who:

(1) Is an officer of PG&E CORP or any Participating Subsidiary and who is in Officer Band 5 or above; or

(2) Is a key employee of PG&E CORP or any Participating Subsidiary and who is designated by the Plan Administrator as eligible to participate in the Plan.

(f) “Eligible Employee’s Account” or “Account” shall mean as to any Eligible Employee, the separate account maintained on the books of the Employer in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.

(g) “Employee” shall mean an individual who is treated in the records of an Employer as an employee of the Employer, who is not on an unpaid leave of absence, and/or who is not covered by a collective bargaining agreement; provided, however, such term shall not mean an individual who is a “leased employee” or who has entered into a written contract or agreement with an Employer which explicitly excludes such individual from participation in an Employer’s benefit plans. The provisions of this definition shall govern, whether or not it is determined that an individual otherwise meets the definition of “common law” employee.

(h) “Employers” shall mean PG&E CORP and the Participating Subsidiaries designated by the Employee Benefit Committee of PG&E CORP. An initial list of the Employers is contained in Appendix A to this Plan.

(i) “ERISA” shall mean the Employee Retirement Income Security Act of 1974, as amended. Reference to a specific section of ERISA shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.

(j) “Investment Funds” shall mean the investment funds established by the Board of Directors and reflected from time to time on Appendix B. The Investment Funds shall be used for tracking phantom investment results under the Plan.

(k) “Matching Employer Contributions” shall mean the amounts credited to Eligible Employees’ Accounts under the Plan by the Employers, in accordance with Section 3(b).

(l) “Participating Subsidiary” shall mean a United States-based subsidiary of PG&E CORP, which has been designated by the Employee Benefit Committee of PG&E CORP as a Participating Subsidiary under this Plan and which has agreed to make payments or reimbursements with respect to its Eligible Employees pursuant to Section 14(d). At such times and under such conditions as the Committee may direct, one or more other subsidiaries of PG&E CORP may become Participating Subsidiaries or a Participating Subsidiary may be withdrawn from the Plan. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.

(m) “PG&E CORP” shall mean PG&E Corporation, a California corporation.

(n) “Plan” shall mean the PG&E Corporation 2005 Supplemental Retirement Savings Plan, as set forth in this instrument and as heretofore and hereafter amended from time to time.

(o) “Plan Year” shall mean the calendar year.

(p) “Prior Plan” shall mean the PG&E Corporation Supplemental Retirement Savings Plan.

(q) “Retirement” or “Retire” shall mean an Eligible Employee’s Separation from Service, provided that the Eligible Employee is at least 55 years of age and has been employed by an Employer for at least five years.

(r) "RSP" shall mean, with respect to any Eligible Employee, the PG&E Corporation Retirement Savings Plan or any predecessor qualified retirement plan sponsored by PG&E CORP or any of its subsidiary companies.

(s) "Separation from Service" shall mean an Eligible Employee's "separation from service" within the meaning of Code Section 409A(a)(2)(A)(i) and related Treasury Regulations and other guidance, as determined by the Plan Administrator in its discretion.

(t) "Valuation Date" shall mean:

(1) For purposes of valuing Plan assets and Eligible Employees' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and

(2) For purposes of determining the amount of assets actually distributed to the Eligible Employee, his or her beneficiary, or an Alternate Payee (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Eligible Employee.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. Employer Contributions.

(a) Matching Employer Contributions. Subject to the provisions of Section 13, the Eligible Employee's Account shall be credited for each Plan Year with a Matching Employer Contribution, calculated in the manner provided in Sections 3(a)(1), (2), and (3) below:

(1) First, an amount shall be calculated equal to the maximum matching contribution that would be made under the terms of the RSP, taking into account for such Plan Year the amount of pre-tax deferrals and after-tax contributions the Eligible Employee elected under the RSP. For purposes of this calculation, any amounts deferred under Subsection 4(a) of this Plan shall be treated as pre-tax deferrals under the RSP.

(2) The calculation made in accordance with this Section 3(a)(1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(m), 401(a)(17), or 415.

(3) The Employer Matching Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(a)(1) and (2) above, reduced by the amount of matching contribution made to such Eligible Employee's account for such Plan Year under the RSP.

(b) Crediting of Matching Employer Contributions. Matching Employer Contributions shall be calculated and credited to the Eligible Employee's Account as of the first business day of February of the calendar year following the Plan Year and shall be credited only

if the Eligible Employee is an Employee on the last day of Plan Year for which the amounts are credited. All such amounts shall be invested in the SRSP Stable Value Fund.

(c) Basic Employer Contributions. Subject to the provisions of Section 13, the Account of each Eligible Employee shall be credited for each Plan Year with a Basic Employer Contribution, calculated in the manner provided in Sections 3(c)(1), (2), and (3) below:

(1) First, an amount shall be calculated equal to the Basic Employer Contribution that would be made under the terms of the RSP, taking into account for such Plan Year the Eligible Employee's Covered Compensation under the RSP, before any deductions for compensation deferrals elected by such Eligible Employee under Subsection 4(a) of this Plan. For Eligible Employees as defined by Section 2(e)(1) of this Plan, compensation shall also reflect such Eligible Employee's Short-Term Incentive Plan awards.

(2) The calculation made in accordance with this Section 3(c)(1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(a)(4), 401(a)(17), or 415.

(3) The Employer Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(c)(1) and (2) above, reduced by the amount of Basic Employer Contributions made to such Eligible Employee's account for such Plan Year under the RSP.

(d) Crediting of Basic Employer Contributions. The Employer Contribution attributable to an Eligible Employee's Short Term Incentive Plan award shall be credited to an Eligible Employee's Account as of the first business day of the month following the date on which the Short-Term Incentive Plan award is paid. All other Employer Contributions made in respect of an Eligible Employee shall be credited to the Eligible Employee's Account as of the first business day of February of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of the Plan Year for which the amounts are credited. All such amounts shall be invested in the SRSP Stable Value Fund.

(e) FICA Taxes. Each Eligible Employee shall be responsible for FICA taxes on amounts credited to his or her Account under Sections 3 and 4(d).

4. Eligible Employee Deferrals.

(a) Amount of Deferral. An Eligible Employee may defer (i) 5 percent to 50 percent of his or her annual salary; and (ii) all or part of his or her Short Term Incentive Plan awards, Long-Term Incentive Plan (LTIP) awards (other than stock options), Perquisite Allowances, and any other special payments, awards, or bonuses as authorized by the Plan Administrator.

(b) Credits to Accounts. Salary deferrals shall be credited to an Eligible Employee's Account as of each payroll period. All other deferrals attributable to allowances, awards, bonuses, and other payments shall be credited as of the date that they otherwise would have been paid.

(c) Deferral Election. An Eligible Employee must file an election form with the Plan Administrator which indicates the percentage of salary and the amount of any awards, allowances, payments, and bonuses to be deferred under the Plan. The election shall occur no later than December 31 (or such earlier date established by the Plan Administrator) of the calendar year next preceding the service year (within the meaning of Treasury Regulation Section 1.409A-2(a)(3)). Notwithstanding the foregoing, to the extent permitted under Treasury Regulation Section 1.409A-2(a)(7), upon first becoming an Eligible Employee, an election to defer shall be effective for compensation to be earned for services performed beginning in the month following the filing of a Deferral Election Form, provided said Form is filed within 30 days following the date when the employee first becomes an Eligible Employee. Notwithstanding the foregoing, in the case of performance-based compensation (within the meaning of Treasury Regulation Section 1.409A-1(e)), the election may be made with respect to such performance-based compensation on or before the date that is six months before the end of the applicable performance period to the extent permitted under Treasury Regulation Section 1.409A-2(a)(8). The Plan Administrator may, in its sole discretion, permit elections to be made under other timing rules that comply with Code Section 409A.

(d) Deferral of Special Incentive Stock Ownership Premiums. All of an Eligible Employee's Special Incentive Stock Ownership Premiums are automatically deferred to the Plan immediately upon grant and converted into units in the PG&E CORP Phantom Stock Fund. The units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon remain unvested until the earlier of the third anniversary of the date on which the Special Incentive Stock Ownership Premiums are credited to an Eligible Employee's account (provided the Eligible Employee continues to be employed on such date), death, disability (within the meaning of Section 22(e)(3) of the Internal Revenue Code), or Retirement of the participant, or upon a Change in Control (as defined in the LTIP). Unvested units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon shall be forfeited upon termination of the Eligible Employee's employment (unless otherwise provided in the PG&E Corporation Executive Stock Ownership Program or the PG&E Corporation Officer Severance Plan) or if an Eligible Employee's stock ownership falls below the levels set forth in the Executive Stock Ownership Program.

5. Investment Funds. Although no assets will be segregated or otherwise set aside with respect to an Eligible Employee's Account, the amount that is ultimately payable to the Eligible Employee with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Eligible Employees' Accounts. Such procedures generally shall provide that an Eligible Employee's Account shall be deemed to be invested among the available Investment Funds in the manner elected by the Eligible Employee in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Eligible Employee, such Account will be deemed to be invested in the SRSP Stable Value Fund. Eligible Employees shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, an Eligible Employee may not reallocate Account balances between

Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested. The available Investment Funds shall be listed on Appendix B and may be changed from time to time by the Board of Directors.

6. Accounting.

(a) Eligible Employees' Accounts. At the direction of the Plan Administrator, there shall be established and maintained on the books of the Employer, a separate account for each Eligible Employee in order to reflect his or her interest under the Plan.

(b) Investment Earnings. Each Eligible Employee's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Eligible Employee's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Eligible Employee's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Eligible Employee's Account.

(c) Accounting Methods. The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Eligible Employees' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.

(d) Valuations and Reports. The fair market value of each Eligible Employee's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Eligible Employees' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Eligible Employee's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.

(e) Statements of Eligible Employee's Accounts. Each Eligible Employee shall be furnished with periodic statements of his or her interest in the Plan.

7. Distributions.

(a) Distribution of Account Balances. Except to the extent the Eligible Employee has elected otherwise under this Section 7 at the time of deferral, distribution of the balance credited to an Eligible Employee's Account shall be made in a single lump sum as soon as reasonably practicable (but in any event within 90 days) following the date that is seven (7) months following Separation from Service .

In the case of an Alternate Payee (as defined in Section 9(a)), to the extent allowable under Code Section 409A, distribution shall be made as directed in a domestic relations order

which the Plan Administrator determines is a QDRO (as defined in Section 9(a)), but only as to the portion of the Eligible Employee's Account which the QDRO states is payable to the Alternate Payee.

(b) "Specific Date" Distributions. By filing an irrevocable election with the Plan Administrator, an Eligible Employee may at the time of deferral elect to receive distribution of the specific type of income deferral for that calendar year plus the earnings thereon (exclusive of Special Incentive Stock Ownership Premiums) in January of any future year instead of pursuant to Section 7(a).

(c) Change in Distribution Election. An Eligible Employee may change a distribution election previously made pursuant to Section 7(b) (or in place by default pursuant to Section 7(a)) only with respect to the portion of the Eligible Employee's Account attributable to Eligible Employee Deferrals (exclusive of Special Incentive Stock Ownership Premiums) and only in accordance with the rules under Code Section 409A. Generally, a subsequent election pursuant to this Section 7(c): (1) cannot take effect for twelve (12) months, (2) must occur at least twelve (12) months before the first scheduled payment under a payment at a specified date elected pursuant to Section 7(b), and (3) must defer a previously elected distribution at least five (5) additional years. The Plan Administrator may establish additional rules or restrictions on changes in distribution elections.

(d) Death Distributions. If an Eligible Employee dies before the balance of his or her Account has been distributed (whether or not the Eligible Employee had previously had a Separation from Service), the Eligible Employee's Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(g), as soon as practicable the date of death (but in any event within 90 days after the date of death).

(e) Special Incentive Stock Ownership Premiums. Distributions attributable to Special Incentive Stock Ownership Premiums shall only be made in the form of one or more certificates for the number of vested Special Incentive Stock Ownership Premium units, rounded down to the nearest whole share, in accordance with the timing rule set forth in Section 7(a).

(f) Effect of Change in Eligible Employee Status. If an Eligible Employee ceases to be an Eligible Employee but does not experience a Separation from Service, the balance credited to his or her Account shall continue to be credited (or debited) with appreciation, depreciation, earnings, gains or losses under the terms of the Plan and shall be distributed to him or her at the time and in the manner set forth in this Section 7.

(g) Payments to Incompetents. If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons

maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.

(h) Beneficiary Designations. Each Eligible Employee may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Eligible Employee's death. An Eligible Employee may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If an Eligible Employee dies without having designated a beneficiary or if no beneficiary survives the Eligible Employee, the Eligible Employee's Account shall be payable to the beneficiary or beneficiaries designated or otherwise determined under the RSP.

(i) Undistributable Accounts. Each Eligible Employee and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Eligible Employee or beneficiary to whom an Eligible Employee's Account is payable under this Section 7, the Eligible Employee's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto. PG&E CORP shall have the right to assign or transfer the liability for payment of any undistributable Account to the Eligible Employee's former Employer (or any successor thereto).

(j) Plan Administrator Discretion. Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

8. Distribution Due to Unforeseeable Emergency (Hardship Distribution). A participant may request a distribution due to an unforeseeable emergency (within the meaning of Code Section 409A) by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a lump sum within 30 days after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. The distribution due to an unforeseeable emergency shall not exceed the amount reasonably necessary to meet the emergency. This Section 8 shall be administered in accordance with the requirements of Code Section 409A.

9. Domestic Relations Orders.

(a) Qualified Domestic Relations Orders. The Plan Administrator shall establish written procedures for determining whether a domestic relations order purporting to dispose of

any portion of an Eligible Employee's Account is a qualified domestic relations order (within the meaning of Section 414(p) of the Code) (a " QDRO ").

(1) No Payment Unless a QDRO. No payment shall be made to any person designated in a domestic relations order (an " Alternate Payee ") until the Plan Administrator (or a court of competent jurisdiction reversing an initial adverse determination by the Plan Administrator) determines that the order is a QDRO. Payment shall be made to each Alternate Payee as specified in the QDRO.

(2) Time of Payment. Payment may be made to an Alternate Payee in the form of a lump sum, at the time specified in the QDRO, but no earlier than the date the QDRO determination is made.

(3) Hold Procedures. Notwithstanding any contrary Plan provision, prior to the receipt of a domestic relations order, the Plan Administrator may, in its sole discretion, place a hold upon all or a portion of an Eligible Employee's Account for a reasonable period of time (as determined by the Plan Administrator in accordance with Code Section 409A) if the Plan Administrator receives notice that (a) a domestic relations order is being sought by the Eligible Employee, his or her spouse, former spouse, child or other dependent, and (b) the Eligible Employee's Account is a source of the payment under such domestic relations order. For purposes of this Section 9(a)(3), a "hold" means that no withdrawals, distributions, or investment transfers may be made with respect to an Eligible Employee's Account. If the Plan Administrator places a hold upon an Eligible Employee's Account pursuant to this Section 9(a)(3), it shall inform the Eligible Employee of such fact.

10. Vesting. Except as provided in Section 4(d), an Eligible Employee's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

11. Administration of the Plan.

(a) Plan Administrator. The Employee Benefit Committee of PG&E CORP is hereby designated as the administrator of the Plan (within the meaning of Section 3(16)(A) of ERISA). The Plan Administrator delegates to the Senior Human Resource Officer for PG&E CORP, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.

(b) Powers of Plan Administrator. The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.

(c) Decisions of Plan Administrator. All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

12. Funding. All amounts credited to an Eligible Employee's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Eligible Employee in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Eligible Employees for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Eligible Employee or beneficiary any interest in or claim against any specific assets of PG&E CORP.

13. Modification or Termination of Plan.

(a) Employers' Obligations Limited. The Plan is voluntary on the part of the Employers, and the Employers do not guarantee to continue the Plan. PG&E CORP at any time may, by appropriate amendment of the Plan, suspend Matching Employer Contributions and/or Basic Employer Contributions or may discontinue Matching Employer Contributions and/or Basic Employer Contributions, with or without cause.

(b) Right to Amend or Terminate. The Board of Directors, acting through its Nominating and Compensation Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.

(1) Limitations. Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

(c) Effect of Termination. If the Plan is terminated, the balances credited to the Accounts of the Eligible Employees affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Eligible Employees' Accounts to the extent provided in Treasury Regulation Sections 1-409A-3(j)(4)(ix) (A) (relating to terminations in connection with certain corporate dissolutions), (B) (relating to terminations in connection with certain change of control events), and (C) (relating to general terminations).

14. General Provisions.

(a) Inalienability. Except to the extent otherwise directed by a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a) or mandated by applicable law, in no event may either an Eligible Employee, a former Eligible Employee or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.

(b) Rights and Duties. Neither the Employers nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.

(c) No Enlargement of Employment Rights. Neither the establishment or maintenance of the Plan, the making of any Matching Employer Contributions, nor any action of any Employer or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as an Employee nor, upon dismissal, any right or interest in any specific assets of the Employers other than as provided in the Plan. Each Employer expressly reserves the right to discharge any Employee at any time, with or without cause or advance notice.

(d) Apportionment of Costs and Duties. All acts required of the Employers under the Plan may be performed by PG&E CORP for itself and its Participating Subsidiaries, and the costs of the Plan may be equitably apportioned by the Plan Administrator among PG&E CORP and the other Employers. Whenever an Employer is permitted or required under the terms of the Plan to do or perform any act, matter or thing, it shall be done and performed by any officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Participating Subsidiary shall be responsible for making benefit payments pursuant to the Plan on behalf of its Eligible Employees or for reimbursing PG&E CORP for the cost of such payments, as determined by PG&E CORP in its sole discretion. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, and PG&E CORP does not exercise its discretion to make the payment on such Participating Subsidiary's behalf, participation in the Plan by the Eligible Employees of that Participating Subsidiary shall be suspended in a manner consistent with Code Section 409A. If at some future date, the Participating Subsidiary makes all past-due payments and reimbursements, plus interest at a rate determined by PG&E CORP in its sole discretion, the suspended participation of its Eligible Employees eligible to participate in the Plan will be recognized in a manner consistent with Code Section 409A. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, an Eligible Employee's (or other payee's) sole recourse shall be against the respective Participating Subsidiary, and not against PG&E CORP. An Eligible Employee's participation in the Plan shall constitute agreement with this provision.

(e) Applicable Law. The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California and, to the extent applicable, ERISA. The Plan is intended to comply with the provisions of Code Section 409A. However, PG&E CORP makes no representation that the benefits provided under the Plan will comply with Code Section 409A and makes no undertaking to prevent Code Section 409A from applying to the benefits provided under the Plan or to mitigate its effects on any deferrals or payments made under the Plan.

(f) Severability. If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.

(g) Captions. The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon

Senior Vice President - Human Resources

APPENDIX A

EMPLOYERS

(As of January 1, 2005)

– PG&E Corporation

– All Participating Subsidiaries

Participating Subsidiaries (as of January 1, 2005):

– Pacific Gas and Electric Company

– All U.S. subsidiaries of the above-named corporations

APPENDIX B

INVESTMENT FUNDS

(as of January 1, 2005)

Participating Investment Funds as of January 1, 2005

AA Utility Bond Fund accrues interest on the amount invested in this fund. The interest rate is equal to the AA Utility Bond Yield reported by Moody's Investor Services.

PG&E Corporation Phantom Stock Fund converts contributions and transferred amounts into units of phantom common stock valued at the closing price of a share of PG&E Corporation common stock on the contribution/transfer date. If the transfer request is received after the market closes, the following day's closing price will be used. Thereafter, the value of a unit shall fluctuate depending on the price of PG&E Corporation common stock. Each time a dividend is paid on common stock, an amount equal to such dividend shall be credited to the account as additional units.

SRSP Large Company Stock Index Fund seeks to match the performance of the S&P 500 Index. The Fund invests in all 500 stocks in the S&P 500 Index in proportion to their weightings in the Index. The S&P 500 provides exposure to about 85% of the market value of all publicly traded common stocks in the United States. The strategy of investing in the same stocks as the S&P 500 Index minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).

SRSP International Stock Index Fund seeks to match closely the performance of the MSCI EAFE Index. The Fund invests in all of the stocks in the MSCI EAFE Index in proportion to their weightings in the Index. The strategy of investing in the same stocks as the MSCI EAFE minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).

SRSP Conservative Asset Allocation Fund is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 60% in Fixed Income Securities, 30% in U.S. Large Cap Equities, 5% in U.S. Small Cap Equities, and 5% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.

SRSP Moderate Asset Allocation Fund is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 40% in Fixed Income Securities, 42% in U.S. Large Cap Equities, 8% in U.S. Small Cap Equities, and 10% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.

SRSP Aggressive Asset Allocation Fund is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 55% in U.S. Large Cap Equities, 20% in Fixed Income Securities, 10% in U.S. Small Cap Equities, and 15% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.

SRSP Stable Value Fund seeks to provide safety of principal and liquidity while providing a higher return over time than that offered by money market funds. The Fund invests in diversified portfolio investment contracts issued by insurance companies, banks, and other financial institutions. An investment contract is an agreement where the issuer promises to pay a specific rate of return to the holder for a period of time. The quality of the promise depends on the financial strength of the issuer. The Fund may also hold a small percentage of cash or other short-term investments. The Fund is managed by PRIMCO Capital Management.

SRSP Bond Index Fund seeks to match the returns of the Lehman Brothers Aggregate Bond Index. The Fund invests primarily in government, corporate, mortgage-backed, and asset-backed fixed-income securities. The Fund invests in a well-diversified portfolio that is representative of the broad domestic bond market. The Lehman Brothers Aggregate Bond Index is an unmanaged market-value weighted index of investment-grade, fixed-rate debt issues, including government, corporate, asset-backed, and mortgage-backed securities, with maturities of one year or more. The Fund is managed by State Street Global Advisors (SSgA).

SRSP Small Company Stock Index Fund seeks to match the performance of the Russell Small Cap Completeness Index. The Fund invests in all of the stocks in the Russell Special Small Cap Completeness Index in proportion to their weightings in the Index. These stocks represent about 15% of the market value of all publicly traded common stocks in the United States. The strategy of investing in the same stocks as the Russell Small Cap Completeness Index minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).



**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

**AMENDMENT AND RESTATEMENT OF
RESTRICTED STOCK UNIT GRANT**

PG&E CORPORATION, a California corporation, granted 24,875 Restricted Stock Units to Peter A. Darbee (the “Recipient”) on May 9, 2008 under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006, December 20, 2006, and October 17, 2007 (the “LTIP”). Effective January 1, 2009, PG&E Corporation and Recipient hereby agree to amend and restate the terms and conditions of such grant of Restricted Stock Units as set forth in the attached Amended and Restated Restricted Stock Unit Agreement (the “Agreement”) in order to make changes to comply with Section 409A of the Internal Revenue Code of 1986 (“Code Section 409A”).

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement.

Recipient: _____
PETER A. DARBEE
(Signature)

Attachment

*Please sign and return to PG&E Corporation, Human Resources,
One Market, Spear Tower, Suite 400, San Francisco, California 94105*

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

**AMENDED AND RESTATED
RESTRICTED STOCK UNIT AGREEMENT**

**The LTIP and Other
Agreements**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict or inconsistency between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Restricted Stock Units

PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.

**Vesting of Restricted Stock
Units**

As long as you remain employed with PG&E Corporation, 100 percent of the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest on the first business day of January of 2013 (the "Vesting Date"). Except as described below, all Restricted Stock Units subject to this Agreement which have not vested shall be cancelled upon termination of your employment.

Dividends

Restricted Stock Units will accrue Dividend Equivalents that will be converted into additional Restricted Stock Units based on the Fair Market Value of a share of PG&E Corporation common stock on the dividend payment date. Such additional Restricted Stock Units will be subject to the same terms and conditions as the underlying Restricted Stock Units.

Settlement

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock. PG&E Corporation shall issue such shares as soon as practicable after the Restricted Stock Units vest upon Vesting Date (but not later than ninety (90) days after the Vesting Date); provided, however, that such issuance shall be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than ninety (90) days after) your separation from service (within the meaning of Code Section 409A), if such separation occurs earlier than the Vesting Date.

Voluntary Termination/ Retirement ¹	In the event of your voluntary termination/Retirement, a prorated portion of the Restricted Stock Units will vest at the time of your separation from service in accordance with the percentage of time you were employed with PG&E Corporation during the vesting period. All other unvested Restricted Stock Units shall be cancelled on the date of termination.
Termination for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation for cause before the Vesting Date, all Restricted Stock Units will be cancelled on the date of termination. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.
Termination other than for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, a prorated portion of the Restricted Stock Units will vest at the time of your separation from service in accordance with the percentage of time you were employed with PG&E Corporation during the vesting period (except as otherwise provided below in connection with a Change in Control). All other unvested Restricted Stock Units shall be cancelled on the date of termination.
Death/Disability	If you separate from service due to your death or Disability, all of your Restricted Stock Units shall vest on the date of separation.
Termination Due to Disposition of Subsidiary	(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the “Code”), or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest in the same manner as for a “Termination other than for Cause” described above.
Change in Control	In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement. If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your outstanding Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and shall be settled on the Vesting Date, subject to earlier settlement upon your separation from service.

¹ Because you have reached age 55 and have been employed by PG&E Corporation for at least five consecutive years, a voluntary resignation would be treated as a retirement.

**Termination In Connection
with a Change in Control**

If your employment is terminated by PG&E Corporation (other than for cause) (i) following a Potential Change in Control (defined below) or (ii) within two years following the Change in Control, all of your outstanding Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of your separation from service.

“Potential Change in Control” shall mean the earliest to occur of (i) the date on which the PG&E Corporation executes an agreement or letter of intent, where the consummation of the transaction described therein would result in the occurrence of a Change in Control, (ii) the date on which the Board of Directors of PG&E Corporation approves a transaction or series of transactions, the consummation of which would result in a Change in Control, or (iii) the date on which a tender offer for PG&E Corporation’s voting stock is publicly announced, the completion of which would result in a Change in Control.

Delay

PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain “key employees” of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your “separation from service” under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period.

Withholding Taxes

Prior to any event in connection with the Restricted Stock Units (e.g., vesting) that PG&E Corporation determines may result in any tax withholding obligation, whether United States federal, state, local , or non-U.S., including any social insurance, employment tax, payment on account , or other tax-related obligation (the “Tax Withholding Obligation”), you must arrange for the satisfaction of the minimum amount of such Tax Withholding Obligation in a manner acceptable to PG&E Corporation.

Subject to any applicable PG&E Corporation policies, at any time not less than five (5) business days (or such fewer number of business days as determined by PG&E Corporation) before any Tax Withholding Obligation arises (e.g., a Vesting Date), you may instruct PG&E Corporation to withhold from those shares otherwise issuable to you the whole number of shares sufficient to satisfy the minimum applicable Tax Withholding Obligation. You acknowledge that the withheld shares may not be sufficient to satisfy your minimum Tax Withholding Obligation. Accordingly, you agree to pay to PG&E Corporation as soon as practicable, including through additional payroll withholding, any amount of the Tax Withholding Obligation that is not satisfied by the withholding of shares described above.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination/Retirement.”

Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a “separation from service” for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

Voting and Other Rights

You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

By signing the cover sheet of this Agreement, you agree to all of the terms and conditions described above and in the LTIP.

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

RESTRICTED STOCK UNIT GRANT

PG&E CORPORATION, a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006, December 20, 2006, October 17, 2007, October 15, 2008, and December 17, 2008 (the "LTIP"). The terms and conditions of the grant of Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: January 2, 2009

Name of Recipient: Peter A. Darbee

Last Four Digits of Recipient's Social Security Number: _____

Number of Restricted Stock Units Granted: 12,693.

By signing this cover sheet, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You also are acknowledging receipt of this Grant and the attached Agreement.

Recipient: PETER A. DARBEE
(Signature)

Attachment

*Please sign and return to PG&E Corporation, Human Resources,
One Market, Spear Tower, Suite 400, San Francisco, California 94105*

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

RESTRICTED STOCK UNIT AGREEMENT

The LTIP and Other Agreements	This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict or inconsistency between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.
Grant of Restricted Stock Units	PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.
Vesting of Restricted Stock Units	As long as you remain employed with PG&E Corporation, 100 percent of the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest on the first business day of January of 2012 (the "Vesting Date"). Except as described below, all Restricted Stock Units subject to this Agreement which have not vested shall be cancelled upon termination of your employment.
Dividends	Restricted Stock Units will accrue Dividend Equivalents that will be converted into additional Restricted Stock Units based on the Fair Market Value of a share of PG&E Corporation common stock on the dividend payment date. Such additional Restricted Stock Units will be subject to the same terms and conditions as the underlying Restricted Stock Units.
Settlement	Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock. PG&E Corporation shall issue such shares as soon as practicable after the Restricted Stock Units vest upon Vesting Date (but not later than ninety (90) days after the Vesting Date); provided, however, that such issuance shall be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions described below) as soon as practicable after (but not later than ninety (90) days after) your separation from service (within the meaning of Code Section 409A), if such separation occurs earlier than the Vesting Date .

Voluntary Termination/Retirement ¹	In the event of your voluntary termination/Retirement, a prorated portion of the Restricted Stock Units will vest at the time of your separation from service in accordance with the percentage of time you were employed with PG&E Corporation during the vesting period. All other unvested Restricted Stock Units shall be cancelled on the date of termination.
Termination for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation for cause before the Vesting Date, all Restricted Stock Units will be cancelled on the date of termination. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.
Termination other than for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, a prorated portion of the Restricted Stock Units will vest at the time of your separation from service in accordance with the percentage of time you were employed with PG&E Corporation during the vesting period (except as otherwise provided below in connection with a Change in Control). All other unvested Restricted Stock Units shall be cancelled on the date of termination.
Death/Disability	If you separate from service due to your death or Disability, all of your Restricted Stock Units shall vest on the date of separation .
Termination Due to Disposition of Subsidiary	(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the “Code”), or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest in the same manner as for a “Termination other than for Cause” described above.
Change in Control	In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement. If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your outstanding Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and shall be settled on the Vesting Date, subject to earlier settlement upon your separation from service.

¹ Because you have reached age 55 and have been employed by PG&E Corporation for at least five consecutive years, a voluntary resignation would be treated as a retirement.

Termination In Connection with a Change in Control	If your employment is terminated by PG&E Corporation (other than for cause) (i) following a Potential Change in Control (defined below) or (ii) within two years following the Change in Control, all of your outstanding Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of your separation from service. "Potential Change in Control" shall mean the earliest to occur of (i) the date on which the PG&E Corporation executes an agreement or letter of intent, where the consummation of the transaction described therein would result in the occurrence of a Change in Control, (ii) the date on which the Board of Directors of PG&E Corporation approves a transaction or series of transactions, the consummation of which would result in a Change in Control, or (iii) the date on which a tender offer for PG&E Corporation's voting stock is publicly announced, the completion of which would result in a Change in Control.
Delay	PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your "separation from service" under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period.
Withholding Taxes	Prior to any event in connection with the Restricted Stock Units (e.g., vesting) that PG&E Corporation determines may result in any tax withholding obligation, whether United States federal, state, local, or non-U.S., including any social insurance, employment tax, payment on account, or other tax-related obligation (the "Tax Withholding Obligation"), you must arrange for the satisfaction of the minimum amount of such Tax Withholding Obligation in a manner acceptable to PG&E Corporation. At any time not less than five (5) business days (or such fewer number of business days as determined by PG&E Corporation) before any Tax Withholding Obligation arises (e.g., a Vesting Date), you may instruct PG&E Corporation to withhold from those shares otherwise issuable to you the whole number of shares sufficient to satisfy the minimum applicable Tax Withholding Obligation. You acknowledge that the withheld shares may not be sufficient to satisfy your minimum Tax Withholding Obligation. Accordingly, you agree to pay to PG&E Corporation as soon as practicable, including through additional payroll withholding, any amount of the Tax Withholding Obligation that is not satisfied by the withholding of shares described above.

Leaves of Absence	For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination/Retirement.” Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a “separation from service” for purposes of any Restricted Stock Units that are settled hereunder upon such separation . To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months. PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.
Voting and Other Rights	You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).
No Retention Rights	This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.
Applicable Law	This Agreement will be interpreted and enforced under the laws of the State of California.

By signing the cover sheet of this Agreement, you agree to all of the terms and conditions described above and in the LTIP.

Exhibit 10.21

Thomas B. King
Executive Vice President and
Chief Operating Officer

Mailing Address:
Mail Code B32
P. O. Box 770000
San Francisco, CA 94177-0001

November 21, 2005

Overnight Mail:
Pacific Gas and Electric Company
77 Beale Street, 32nd Floor

Mr. John S. Keenan
108 Braewyns Lane
Holly Springs, NC 27540

415.973.7431
Fax: 415.973.9485

Dear Jack:

On behalf of Pacific Gas and Electric Company, I am pleased to extend a revised offer to you to join our organization as Senior Vice President, Generation and Chief Nuclear Officer, reporting to me.

Your initial total compensation package will consist of the following:

1. An annual base salary of \$350,000 (\$29,166.67/month) subject to possible increases through our annual salary review plan.
 2. A one-time bonus of \$200,000 payable within 60 days of your date of hire, subject to normal tax withholdings. Should you leave the company or should your employment be terminated for cause within three years of your date of hire, a prorated amount of this bonus must be refunded to the company.
 3. A target incentive of \$175,000 (50% of your base salary) in an annual short-term incentive plan under which your actual incentive dollars may range from zero to \$350,000 based on performance relative to established goals. If your date of hire is in 2005, this incentive will be prorated for the number of months worked from your date of hire and will be payable in 2006.
 4. A one-time additional incentive tied to the improvement of the performance of Diablo Canyon Power Plan (DCPP). Specifically, 50 percent of your 2006 annual short-term incentive plan award will be tracked in a phantom account contingent upon INPO's next rating of DCPP, which is scheduled to occur in the spring of 2007. If the 2007 INPO rating is a 1, the amount tracked in the phantom account will be paid to you.
 5. Participation in the PG&E Corporation Long-Term Incentive Plan (LTIP) as a band 3 officer. Grants under the LTIP are split equally between restricted stock and performance shares, and are generally made annually on the first business day of the year. Your initial grant will be made on the first business day of January 2006 and will have an estimated current value of \$400,000. This estimated value is used only for the purpose of determining the number of shares for your grant. The ultimate value that you realize from this grant will depend upon your employment status and the performance of PG&E Corporation common stock.
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6. A one-time supplement LTIP grant with an estimated current value of \$200,000. This grant will be apportioned and made in the same manner as the grant described in item 5.
 7. Participation in the PG&E Corporation Supplemental Executive Retirement Plan (SERP). The basic benefit payable from the SERP at retirement is a monthly annuity equal to the product of 1.7% x [average of the three highest years' combination of salary and annual incentive for the last ten years of service] x years of credited service x 1/12 less any amounts paid or payable from the Pacific Gas and Electric Company Retirement Plan (RP). During each of your first seven complete years of employment, you will receive 1½ years of credited service, resulting in a total of 10½ years of service at the end of seven years of employment. Thereafter, you will receive one year of credited service for each additional year of employment.
 8. Conditioned upon meeting plan requirements, you will also be eligible for post-retirement life insurance and post-retirement medical benefits upon retirement under the RP.
 9. Participation in the PG&E Corporation Retirement Savings Plan (RSP), a 401(k) savings plan. You will be eligible to contribute as much as 20% of your salary on either a pre-tax or after-tax basis. After your first year of service, we will match contributions you make up to 3% of your salary at 75 cents on each dollar contributed. After three years of service, we will match contributions up to 6% of your salary at 75 cents on each dollar contributed. All of the above contributions are subject to the applicable legal limits.
 10. Participation in the PG&E Corporation Supplemental Retirement Savings Plan (SRSP), a non-qualified, deferred compensation plan. You may elect to defer payment of some of your compensation on a pre-tax basis. We will provide you with the full matching contributions that cannot be provided through the RSP, due to legal limitations imposed on highly compensated employees.
 11. As a result of your officer level (officer band 3), you will become an eligible participant under the Executive Stock Ownership Program effective January 1, 2007. As an ancillary benefit to that program, you will also be eligible to receive financial counseling from The AYCO Company at a subsidized rate to assist you in your understanding of our compensation and benefits programs and how those programs can help you to achieve financial security. For this feature of the program, you will be eligible as of January 1, 2006.
 12. Participation in a cafeteria-style benefits program that permits you to select coverage tailored to your personal needs and circumstances. The benefits you elect will be effective the first of the month following the date of your hire.
 13. An annual vacation allotment of four weeks, subject to future increases based on length of service. If your date of hire is in 2005, the vacation allotment will be prorated based on your date of hire. In addition, Pacific Gas and Electric Company recognizes 10 paid company holidays annually and provides 3 floating holidays immediately upon hire and at the beginning of each year.
 14. An annual perquisite allowance of \$20,000 to be used in lieu of individual authorizations for cars and memberships in clubs and civic organizations. If your date of hire is in 2005, you will receive half of this amount (\$10,000) for 2005.
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15. Participation in the Employee Discount program after six months of continuous service following your date of hire. The program offers participant's a 25% discount on electricity and gas rates for their primary residence. In order to receive this benefits, you must (a) live within Pacific Gas and Electric Company's service territory and (b) have the service in your name at your primary residence.

As we have discussed, this offer is contingent upon your passing a comprehensive background verification including a credit check and security clearance assessment, and a standard drug analysis test. We will also need to verify your eligibility to work in the United States based on applicable immigration laws. In addition, your election as an officer of Pacific Gas and Electric Company is subject to approval by the Board of Directors of Pacific Gas and Electric Company and elements of your compensation are subject to approval by the Nominating, Compensation, and Governance Committee of the Board of Directors of PG&E Corporation.

Peter Darbee and I look forward to your joining our team and believe you will make a strong contribution to the achievement of the mission and goals of Pacific Gas and Electric Company and PG&E Corporation. I would appreciate receiving your written acceptance of this offer as soon as possible. Please call me at any time if you have any questions.

Sincerely,

THOMAS B. KING

THOMAS B. KING

Attachment

This is to confirm my acceptance of Pacific Gas and Electric Company's offer as the Senior Vice President, Generation and Chief Nuclear Officer as outlined above.

JOHN S. KEENAN
11/28/05

(Signature and Date)

PG&E CORPORATION
2005 DEFERRED COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

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PG&E CORPORATION

2005 DEFERRED COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

This is the controlling and definitive statement of the PG&E CORPORATION (“PG&E CORP”) 2005 Deferred Compensation Plan for Non-Employee Directors (the “Plan”). The Plan was amended for compliance with the final Code Section 409A regulations effective as of January 1, 2009. Except as provided herein, the Plan is effective as of January 1, 2005, with respect to all individuals who are Directors as of such date. The Plan continues the program embodied in the PG&E Corporation Deferred Compensation Plan for Non-Employee Directors (the “Prior Plan”).

1. Purpose of the Plan. The Plan is established and is maintained for the benefit of Directors of PG&E CORP in order to provide the Directors with an opportunity to defer receipt of their Meeting Fees and Retainer Fees. The Plan is an unfunded deferred compensation plan.
2. Definitions. The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:
 - (a) “Board of Directors” shall mean the Board of Directors of PG&E CORP, as from time to time constituted.
 - (b) “Code” shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
 - (c) “Committee” shall mean the Compensation Committee of the Board of Directors, as it may be constituted from time to time.
 - (d) “Deferred Compensation Account” or “Account” shall mean as to any Director, the separate account maintained on the books of PG&E CORP in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.
 - (e) “Director” shall mean any member of the Board of Directors who is not an employee of PG&E CORP or a Subsidiary.
 - (f) “Director's Termination Date” shall mean the date of the Director's separation from service (within the meaning of Section 409A of the Code).
 - (g) “Investment Funds” shall mean the investment funds established by the Board of Directors and reflected from time to time on Appendix A. The Investment Funds shall be used for tracking phantom investment results under the Plan.
 - (h) “Meeting Fee” means the amount of compensation paid by PG&E CORP to a Director for his or her attendance and services at a meeting of the Board of Directors or any committee thereof. A Meeting Fee shall not include (i) any Retainer Fee, or (ii) any reimbursement by PG&E CORP of expenses incurred by a Director incidental to attendance at a

meeting of the Board of Directors or of a committee thereof or of any other expense incurred on behalf of PG&E CORP.

(i) “ PG&E CORP ” shall mean PG&E Corporation, a California corporation.

(j) “ Plan ” shall mean the PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as set forth in this instrument and as amended from time to time.

(k) “ Plan Year ” shall mean the calendar year.

(l) “ Prior Plan ” shall mean the PG&E Corporation Deferred Compensation Plan for Non-Employee Directors.

(m) “ Retainer Fee ” means the amount of compensation paid by PG&E CORP to a Director for retaining his or her services during a calendar quarter. A Retainer Fee shall not include (i) any Meeting Fee, or (ii) any reimbursement by PG&E CORP of expenses incurred by a Director incidental to attendance at a meeting of the Board of Directors or of a committee thereof or of any other expense incurred on behalf of PG&E CORP.

(n) “ Subsidiary ” shall mean a subsidiary of PG&E CORP.

(o) “ Valuation Date ” shall mean:

(1) For purposes of valuing Plan assets and Directors’ Accounts for periodic reports and statements, the date as of which such reports or statements are made; and

(2) For purposes of determining the amount of assets actually distributed to the Director or his or her beneficiary (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Director.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. Eligibility. Each Director who receives a Meeting Fee or Retainer Fee for service on the Board of Directors shall be eligible to participate in the Plan.

4. Deferrals.

(a) Amount of Deferral. A participating Director may defer (i) all Retainer Fees only; (ii) Meeting Fees only; or (iii) all Retainer Fees and all Meeting Fees.

(b) Credits to Accounts. Deferrals shall be credited to a Director’s Account as of the date that they otherwise would have been paid.

(c) Deferral Election. A Director must file an election form with the Corporate Secretary which indicates whether Retainer Fees, Meeting Fees or both are to be deferred under the Plan. The election shall occur no later than December 31 (or such earlier date established by the Plan Administrator) of the calendar year next preceding the service year (within the meaning of Treasury Regulation Section 1.409A-2(a)(3)). Notwithstanding the foregoing, to the extent permitted under Treasury Regulation Section 1.409A-2(a)(7), upon first becoming a Director, an election to defer shall be effective for Meeting Fees and/or Retainer Fees earned with respect to service provided following the filing of a Deferral Election Form, provided said Form is filed with the Corporate Secretary within 30 days following the date when the individual first becomes a Director. The Plan Administrator may, in its sole discretion, permit elections to be made under other timing rules that comply with Code Section 409A.

5. Investment Funds. Although no assets will be segregated or otherwise set aside with respect to a Director's Account, the amount that is ultimately payable to the Director with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Directors' Accounts. Such procedures generally shall provide that a Director's Account shall be deemed to be invested among the available Investment Funds in the manner elected by the Director in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Director, such Account will be deemed to be invested in the AA Utility Bond Fund. Directors shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, a Director may not reallocate Account balances between Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested. The available Investment Funds shall be listed on Appendix A and may be changed from time to time by the Board of Directors.

6. Accounting.

(a) Accounts. At the direction of the Plan Administrator, there shall be established and maintained on the books of PG&E CORP, a separate account for each participating Director in order to reflect his or her interest under the Plan.

(b) Investment Earnings. Each Director's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Director's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Director's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Director's Account.

(c) Accounting Methods. The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Directors' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be

revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.

(d) Valuations and Reports . The fair market value of each Director's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Directors' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Director's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.

(e) Statements of Director's Accounts . Each Director shall be furnished with periodic statements of his or her interest in the Plan by January 31 of each year.

7. Distributions .

(a) Distribution of Account Balances. Except to the extent the Director has elected otherwise under Section 7 (b) or Section 7(c) at the time of a deferral election or Section 7(e) applies , distribution of the balance credited to a Director's Account shall be made in a single lump sum in January of the year following the Director's Termination Date.

(b) Installment Distributions . In lieu of a single sum payment under Section 7(a) or 7(c), a Director may at the time of deferral elect in writing and file with the Plan Administrator an election that payment of amounts credited to the Director's Account be made in 10 approximately equal annual installments. However, if during the installment payment period the Account balance is less than \$5,000, the value of the remaining installments shall be paid as a lump sum. Installment payments (including a final payment pursuant to the preceding sentence) will be made in January of the year following the Director's Termination Date and on each anniversary thereof until all installments are paid.

(c) " Specific Date" Distributions . By filing an irrevocable election with the Plan Administrator, a Director may at the time of deferral elect to commence distribution of full or partial payment of the balance of his or her Account in January of any future year instead of pursuant to Section 7(a).

(d) Change in Distribution Election . A Director may change a distribution election previously made pursuant to Section 7(b) or Section 7(c) only in accordance with the rules under Code Section 409A. Generally, a subsequent election pursuant to this Section 7(d): (1) cannot take effect for twelve (12) months, (2) must occur at least twelve (12) months before the first scheduled payment under a payment at a specified date elected pursuant to Section 7(c), and (3) must defer a previously elected distribution at least five (5) additional years from the date payment would have otherwise been made. The Plan Administrator may establish additional rules or restrictions on changes in distribution elections.

(e) Death Distributions . If a Director dies before the entire balance of his or her Account has been distributed (whether before or after the Termination Date and whether or not installment payments had previously commenced), the remaining balance of the Director's

Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(g), as soon as practicable (but in any event within 90 days) after the date of death.

(f) Payments to Incompetents. If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.

(g) Beneficiary Designations. Each Director may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Director's death. A Director may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If a Director dies without having designated a beneficiary or if no beneficiary survives the Director, the Director's Account shall be payable to the estate or the last to die of the Director.

(h) Undistributable Accounts. Each Director and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Director or beneficiary to whom a Director's Account is payable under this Section 7, the Director's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto.

(i) Plan Administrator Discretion. Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

(j) Specified Employees. Notwithstanding anything in this Plan to the contrary, the Plan Administrator shall delay any payment under this Plan to the extent necessary to comply with Code Section 409A(a)(2)(B)(i) (relating to payments made to certain "specified employees" of certain publicly-traded companies) and in such event, any such amount to which the affected Directors would otherwise be entitled during the six (6) month period immediately following the Director's Termination Date (or shorter period ending on the date of the Director's death following the Director's Termination Date) will be paid on the first business day following the expiration of the applicable delay period.

8. Distribution Due to Unforeseeable Emergency (Hardship Distribution). A participant may request a distribution due to an unforeseeable emergency (within the meaning of Code Section 409A) by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a lump sum within 30 days after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. A participant who has commenced receiving installment payments under the Plan may request acceleration of such payments in the event of an unforeseeable emergency. The distribution due to an unforeseeable emergency shall not exceed the amount reasonably necessary to meet the emergency. This Section 8 shall be administered in accordance with the requirements of Code Section 409A.

9. Vesting. A Director's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

10. Administration of the Plan.

(a) Plan Administrator. The Committee is hereby designated as the administrator of the Plan. The Plan Administrator delegates to the Corporate Secretary, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.

(b) Powers of Plan Administrator. The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.

(c) Decisions of Plan Administrator. All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

11. Funding. All amounts credited to a Director's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Director in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Directors for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Director or beneficiary any interest in or claim against any specific assets of PG&E CORP.

12. Modification or Termination of Plan.

(a) Obligations Limited. The Plan is voluntary on the part of PG&E CORP, and PG&E CORP does not guarantee to continue the Plan.

(b) Right to Amend or Terminate. The Board of Directors, acting through its Compensation Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.

(1) Limitations. Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

(c) Effect of Termination. If the Plan is terminated, the balances credited to the Accounts of the Directors affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Directors' Accounts to the extent provided in Treasury Regulation Sections 1-409A-3(j)(4)(ix) (A) (relating to terminations in connection with certain corporate dissolutions), (B) (relating to terminations in connection with certain change of control events), and (C) (relating to general terminations).

13. General Provisions.

(a) Inalienability. Except to the extent mandated by applicable law, in no event may either a Director, a former Director or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.

(b) Rights and Duties. Neither PG&E CORP nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.

(c) No Enlargement of Rights. Neither the establishment or maintenance of the Plan, nor any action of PG&E CORP or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as a Director nor, upon dismissal, any right or interest in any specific assets of PG&E CORP other than as provided in the Plan. PG&E CORP expressly reserves the right to remove any Director at any time, with or without cause or advance notice.

(d) Applicable Law. The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California.

(e) Severability. If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.

(f) Captions. The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President - Human Resources

APPENDIX A
INVESTMENT FUNDS
(as of January 1, 2005)

Participating Investment Funds as of January 1, 2005

(1) AA Utility Bond Fund. Interest shall be credited on the amounts invested in the AA Utility Bond Fund. Such interest shall be at a rate equal to the AA Utility Bond Yield reported by Moody's Investors Service. Such interest shall become a part of the Director's Account and shall be paid at the same time or times as the balance of the Director's Account.

(2) PG&E CORP Phantom Stock Fund. Amounts credited to the PG&E CORP Phantom Stock Fund shall be converted into units (including fractions computed to three decimal places) each representing a share of PG&E CORP common stock. The value of a unit for purposes of determining the number of units to credit upon initial allocation or upon reallocation from another Investment Fund, and for determining the dollar value of the aggregate number of units to be reallocated from the PG&E CORP Phantom Stock Fund to another Investment Fund and for distributions from the Plan, shall be the closing price of a share of PG&E CORP common stock as traded on the New York Stock Exchange on the date that (i) amounts are credited to a Director's Account in the PG&E CORP Phantom Stock Fund, or (ii) the Plan Administrator receives a reallocation request, in the case of reallocations. If such credit or reallocation occurs after close of the New York Stock Exchange on that day, the price shall be based on the closing price of a share of PG&E CORP common stock on the next day on which such shares are traded on the New York Stock Exchange. Thereafter, the value of a unit shall fluctuate in accordance with the closing price of PG&E CORP common stock on the New York Stock Exchange. Each time that PG&E CORP pays a dividend on its common stock, an amount equal to such dividend payable with respect to each share of PG&E CORP common stock, multiplied by the number of units credited to a Director's Account, shall be credited to the Director's Account and converted into additional units. The number of additional units shall be calculated by dividing the aggregate amount of credited dividends, i.e., the dividend multiplied by the number of units credited to the Director's Account as of the dividend record date, by the closing price of a share of PG&E CORP common stock on the New York Stock Exchange on the dividend payment date. If, after the record date but before the dividend payment date, a Director's balance in the PG&E CORP Phantom Stock Fund has been reallocated to another Investment Fund(s) or has been paid to the Director or to the Director's beneficiary, other than pursuant to an election under Sections 7(c)(2) or 8, then an amount equal to the aggregated dividend shall be credited to the Director's Account in such other Investment Fund(s) or paid directly to the Director or the Director's beneficiary, whichever is applicable.

2009 OFFICER SHORT-TERM INCENTIVE PLAN

On February 17, 2009, the Compensation Committee of the PG&E Corporation Board of Directors (“Committee”) approved the specific performance targets for each component of the 2009 Short-Term Incentive Plan (“STIP”). The Committee previously approved the STIP structure and the weighting of each component in December 2008. Officers of PG&E Corporation and the Utility are eligible to receive cash incentives under the STIP based on the extent to which the adopted 2009 performance targets are met. The Committee will continue to retain full discretion as to the determination of final officer STIP payments.

The corporate financial performance target, with a weighting of 50%, is based on PG&E Corporation’s budgeted earnings from operations that were previously approved by the Board of Directors, consistent with the basis for reporting and guidance to the financial community. As with previous earnings performance scales, unbudgeted items impacting comparability such as changes in accounting methods, workforce restructuring, and one-time occurrences will be excluded.

The Committee also approved the 2009 performance targets for each of the four other measures set forth in the table below. The 2008 performance results for each of these measures are included for comparative purposes.

2009 STIP Operational Performance Targets ⁽¹⁾

Measure	Relative Weight	2008 Results	2009 Target
Customer Satisfaction and Brand Health Index (Residential & Business) ⁽²⁾	17.5%	76.1	76.1
Reliable Energy Delivery Index ⁽³⁾	17.5%	1.443	1.0
Employee Survey (Premier) Index ⁽⁴⁾	5%	68.57%	69.5%
Occupational Safety and Health Administration (OSHA) Recordable Injury Rate ⁽⁵⁾	10%	3.241	2.755

- As explained above, 50% of the STIP award will be based on achievement of corporate earnings from operations targets.
- The Customer Satisfaction and Brand Health Index is the result of a quarterly survey performed by an independent research firm, Research International, and is a combination of a customer satisfaction score, which has a 75% weighting, as well as a brand favorability score (measuring the relative strength of the PG&E brand against a select group of companies), which has a 25% weighting. The customer satisfaction score will measure overall satisfaction with the Utility’s operational performance in delivering its services. The brand favorability score will measure residential, small business and medium business customer perceptions.
- The Reliable Energy Delivery Index is a composite index score that measures leading indicators of electric and gas reliability performance, including electric outage frequency and duration (System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI)) and performance improvement in the resurvey of the Utility’s gas system.
- The Premier Survey is the primary tool used to measure employee engagement at PG&E Corporation and the Utility. The employee index is designed around 15 key drivers of employee engagement and organizational health. The average overall employee survey index score provides a comprehensive metric that is derived by adding the percent of favorable responses from all 40 core survey items (all of which fall into one of 15 broader topical areas), and then dividing the total sum by 40.
- An “OSHA Recordable” is an occupational (job-related) injury or illness that requires medical treatment beyond first aid, or results in work restrictions, death or loss of consciousness. The “OSHA Recordable Rate” is the number of OSHA Recordables for every 200,000 hours worked, or for approximately 100 employees. This metric measures the percentage reduction in the PG&E Corporation’s and the Utility’s OSHA Recordable rate from the prior year and is used to monitor the effectiveness of the companies’ safety programs, which are intended to significantly reduce the number and degree of employee injuries and illnesses.

Cash awards under the STIP may range from 30 percent to 100 percent of base salary depending on officer level, with a maximum payout of 200 percent of the officer’s targeted award, as determined by the Committee.

[PG&E CORPORATION LETTERHEAD]**AMENDMENT TO SHORT-TERM INCENTIVE PROGRAMS
AND OTHER BONUS PROGRAMS**

All current and future bonus plans of PG&E Corporation ("PG&E") with an annual (or shorter) performance period (the "Plans") are hereby amended as described below, effective January 1, 2009.

1. Payments under the Plans shall be made within two months and 15 days following the end of the calendar year in which such payments cease to be subject to a "substantial risk of forfeiture," within the meaning of Section 409A of the Internal Revenue Code of 1986 ("Section 409A"). In the event that PG&E's taxable year ceases to be the calendar year, then payments under the Plans shall be made within two months and 15 days following the later of the end of the calendar year or PG&E's taxable year in which such payments cease to be subject to a "substantial risk of forfeiture," within the meaning of Section 409A.

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President - Human Resources

[UTILITY LETTERHEAD]**AMENDMENT TO SHORT-TERM INCENTIVE PROGRAMS
AND OTHER BONUS PROGRAMS**

All current and future bonus plans of the Pacific Gas and Electric Company ("PG&E") with an annual (or shorter) performance period (the "Plans") are hereby amended as described below, effective January 1, 2009.

1. Payments under the Plans shall be made within two months and 15 days following the end of the calendar year in which such payments cease to be subject to a "substantial risk of forfeiture," within the meaning of Section 409A of the Internal Revenue Code of 1986 ("Section 409A"). In the event that PG&E Corporation's taxable year ceases to be the calendar year, then payments under the Plans shall be made within two months and 15 days following the later of the end of the calendar year or PG&E Corporation's taxable year in which such payments cease to be subject to a "substantial risk of forfeiture," within the meaning of Section 409A.

IN WITNESS WHEREOF, Pacific Gas and Electric Company has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President - Human Resources

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
PG&E CORPORATION
(As Amended Effective as of January 1, 2009)

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan (“PLAN”)¹ for ELIGIBLE EMPLOYEES of PG&E Corporation (“CORPORATION”), Pacific Gas and Electric Company (“COMPANY”) and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN is the successor plan to the Supplemental Executive Retirement Plan of the COMPANY. The PLAN as contained herein was first adopted effective January 1, 2005.

ARTICLE 1

DEFINITIONS

- 1.01 Basic SERP Benefit shall mean the benefit described in Section 2.01.
- 1.02 Board or Board of Directors shall mean the BOARD OF DIRECTORS of the CORPORATION or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.
- 1.03 Company shall mean the Pacific Gas and Electric Company, a California corporation.
- 1.04 Corporation shall mean PG&E Corporation, a California corporation.
- 1.05 Eligible Employee shall mean (1) employees (a) of the COMPANY or (b) with respect to PG&E Corporation, PG&E Corporation Support Services, Inc., and PG&E Corporation Support Services II, Inc. only, (i) prior to April 1, 2007, employees who transferred to PG&E Corporation, PG&E Corporation Support Services, Inc., or PG&E Corporation Support Services II, Inc. from Pacific Gas and Electric Company; or (ii) after March 31, 2007, all employees, (2) who are officers in Officer Bands I-V, and (3) such other employees of the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chief Executive Officer of the CORPORATION. ELIGIBLE EMPLOYEES shall not include employees who retired prior to January 1, 2005, or whose employment relationship with any of the PARTICIPATING EMPLOYERS was otherwise terminated prior to January 1, 2005.
- 1.06 STIP Payment shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by the CORPORATION.

¹ Words in all capitals are defined in Article I.

1.07 Participating Employer shall mean the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., and any other companies, affiliates, subsidiaries or associations designated by the Chief Executive Officer of the CORPORATION.

1.08 Plan shall mean the Supplemental Executive Retirement Plan (“ SERP ”) as set forth herein and as may be amended from time to time.

1.09 Plan Administrator shall mean the Employee Benefit Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.10 Retirement Plan shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.11 Salary shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts that have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.12 Service shall mean “ credited service ” as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, “ credited service ” as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE 2

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity with an annuity start date of the later of (a) the first of the month following the month in which the ELIGIBLE EMPLOYEE has a separation from service (as provided under Code Section 409A and related guidance), or (b) the first of the month following the ELIGIBLE EMPLOYEE’s 55th birthday; provided, however, that no payments under the PLAN shall be made until the seventh month following the annuity start date. The first payment shall consist of the monthly annuity payment for the seventh month, plus the first six monthly annuity payments, including interest calculated at a rate to reflect the CORPORATION’s marginal cost of funds. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

$1.7\% \times \text{the average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE} \times \text{SERVICE} \times 1/12.$

In computing a year’s combination of SALARY and STIP PAYMENT, the year’s amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years’ SALARY, the average

shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

The BASIC SERP BENEFIT is a benefit commencing at age 65. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.02 For ELIGIBLE EMPLOYEES of the PARTICIPATING EMPLOYERS, who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms that are actuarially equivalent within the meaning of Treasury Regulations Section 1.409A-2(b)(ii) , with the first annuity payment commencing at the time set forth in Section 2.01 :

(a) BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

(b) A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE's death. Subject to the requirements of Treasury Regulations Section 1.409A-2(b)(ii) , the factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

An ELIGIBLE EMPLOYEE may make this election by the latest date permitted by the PLAN ADMINISTRATOR and in compliance with the rules of Treasury Regulations Section 1.409A-2(b)(2)(ii).

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension

plans under Section 415 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN.

ARTICLE 3

DEATH BENEFITS

3.01 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence and the ELIGIBLE EMPLOYEE is married at the time of the ELIGIBLE EMPLOYEE's death, the PLAN ADMINISTRATOR shall pay a spouse's benefit to the ELIGIBLE EMPLOYEE's surviving spouse:

(a) If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 or older at the time of death, the spouse's benefit shall be a monthly annuity commencing at the time set forth in Section 2.01 and shall be payable for the life of the surviving spouse. The amount of the monthly benefit shall be a monthly benefit that is actuarially equivalent to one-half of the monthly BASIC SERP BENEFIT that would have been paid to the ELIGIBLE EMPLOYEE calculated:

(i) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option; and

(ii) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and

(iii) without the application of early retirement reduction factors. However, if the spouse is more than 10 years younger than the ELIGIBLE EMPLOYEE, the amount of the spouse's benefit shall be reduced one-twentieth of 1 percent for each full month in excess of 120 months' difference in their ages, except that such reduction shall not result in a spouse's benefit lower than would have been payable if the ELIGIBLE EMPLOYEE had retired as of the date of death and elected a 50 percent joint pension with a spouse of the same gender and age as the surviving spouse.

(b) If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of death, the surviving spouse will be entitled to receive a monthly annuity commencing at the time set forth in Section 2.01. The amount of the monthly annuity payable to the surviving spouse shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments at age 55, and 4) had subsequently died.

(c) If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.

(d) If a former ELIGIBLE EMPLOYEE was younger than age 55 and had fewer than 70 points (as calculated under Section 3.01(a)) at the time of his death, the surviving spouse will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT at age 55, and 3) had subsequently died.

3.02 A surviving spouse who is entitled to receive a spouse's benefit under Section 3.01 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE 4

ADMINISTRATIVE PROVISIONS

4.01 Administration. The PLAN shall be administered by the Senior Human Resources Officer of the CORPORATION (" PLAN ADMINISTRATOR "), who shall have the authority to interpret the PLAN and make and revise such rules as he or she deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 Amendment and Termination. The CORPORATION may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the CORPORATION may (but is not obligated to) reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant, is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the CORPORATION that preserves the time and form of payment rules under the PLAN and otherwise in a manner that complies with Code Section 409A, to the extent required to not violate Code Section 409A.

4.03 Nonassignability of Benefits. Except to the extent otherwise directed by a domestic relations order that the Plan Administrator determines is a Qualified Domestic

Relations Order under Section 401(a)(12) of the Internal Revenue Code, the benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 Nonguarantee of Employment. Nothing contained in this PLAN shall be construed as a contract of employment between a PARTICIPATING EMPLOYER and the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of a PARTICIPATING EMPLOYER, to remain as an officer of a PARTICIPATING EMPLOYER, or as a limitation on the right of a PARTICIPATING EMPLOYER to discharge any of its employees, with or without cause.

4.05 Apportionment of Costs. The costs of the PLAN may be equitably apportioned by the PLAN ADMINISTRATOR among the PARTICIPATING EMPLOYERS. Each PARTICIPATING EMPLOYER shall be responsible for making benefit payments pursuant to the PLAN on behalf of its ELIGIBLE EMPLOYEES or for reimbursing the CORPORATION for the cost of such payments, as determined by the CORPORATION in its sole discretion. In the event the respective PARTICIPATING EMPLOYER fails to make such payment or reimbursement, and the CORPORATION does not exercise its discretion to make the contribution on such PARTICIPATING EMPLOYER's behalf, future benefit accruals of the ELIGIBLE EMPLOYEES of that PARTICIPATING EMPLOYER shall be suspended. If at some future date, the PARTICIPATING EMPLOYER makes all past-due contributions, plus interest at a rate determined by the PLAN ADMINISTRATOR in his or her sole discretion, the benefit accrual of its ELIGIBLE EMPLOYEES will be recognized for the period of the suspension.

4.06 Benefits Unfunded and Unsecured. The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the CORPORATION.

4.07 Applicable Law. All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California. The PLAN is intended to comply with the provisions of Code Section 409A. However, the CORPORATION makes no representation that the benefits provided under this PLAN will comply with Code Section 409A and makes no undertaking to prevent Code Section 409A from applying to the benefits provided under this PLAN or to mitigate its effects on any deferrals or payments made under this PLAN.

4.08 Satisfaction of Claims. Notwithstanding Section 4.05 or any other provision of the PLAN, the CORPORATION may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance

company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the CORPORATION and shall be subject to the ELIGIBLE EMPLOYEE's acknowledgement that the CORPORATION's obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the CORPORATION may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President - Human Resources

HOMEOWNERS RELOCATION ASSISTANCE

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ELIGIBILITY

In order to qualify for relocation assistance:

- Your new commute must be AT LEAST 50 miles FURTHER than your current commute. To determine eligibility:

Mileage from CURRENT home to NEW headquarters: _____ miles
Mileage from CURRENT home to CURRENT headquarters: (_____ miles)
Difference must equal 50 miles or more. _____ miles

The relocation must result in a commute which is substantially reduced, that is by at least 50 percent. Your new residence must be closer to the new headquarters than the former residence.

- Moves over 100 miles require the new residence to be within 50 miles of the new headquarters. You are encouraged to consult with Relocation Services to verify the maximum allowable distance from the new headquarters.
- Moves less than 100 miles require that the commute be reduced by at least 50 percent.
- You must relocate your primary residence within one year from the effective date of hire. Establishing a permanent residence is defined as the employee **and** family establishing a permanent tax base. Traveling back to the principle residence on weekends from an apartment, mobile home, motor home, rented room or company housing will not qualify for relocation assistance.

PAYBACK AGREEMENT

You will be asked to sign a Relocation Payback Agreement. Please read this document carefully and return it directly to Relocation Services in the envelope provided.

No payments will be made or services requested until a signed copy of this agreement is on file.

RELOCATION ASSISTANCE CHECKLIST

1. Home Sale	Homeowner *
A. Home Sale Assistance Program	Yes
B. Direct Reimbursement for Closing Costs	Yes
2. Move Allowance	Yes
3. House Hunting Trip	Yes
4. Enroute Expenses	Yes
5. Corporate Housing (temporary housing)	Yes
6. Moving	
A. Household Move	Yes
B. Household Storage	90 days
C. Delivery out of Storage	Yes
7. Home Purchase Closing Costs	Yes
8. Mortgage Interest Differential Allowance (MIDA)	Yes (1)

*Status at the time of the job interview. Mobile homes do not qualify for the Home Sale Assistance Program.

- (1) In order to qualify, new rate must be at least 10 percent and exceed current rate by at least 2 percent.

NOTE: All relocation assistance must be requested within **one year** of the effective date of hire.

Reimbursements NOT submitted within **one year** will be denied.
Receipts must be provided.

In addition to other policy provisions regarding the timing of expense reimbursements, any reimbursements of taxable expenses provided pursuant to this program shall be reimbursed on or before the last day of the calendar year following the year in which the expense was incurred, consistent with requirements in Internal Revenue Code Section 409A, as it may be amended.

The amount of expenses eligible for reimbursement is not subject to a multi-year cap. As a result, expenses eligible for reimbursement during one year do not affect the expenses eligible for reimbursement in any other taxable year.

MOVE ALLOWANCE

The Move Allowance is intended to help defray some of the miscellaneous relocation expenses not directly reimbursed by policy. Receipts will not be required.

The only action required by the employee is to return the Relocation Expense Payback Agreement and Home Sale Assistance Agreement, if appropriate.

It should be noted that if an employee accepts the Move Allowance and does not complete the relocation process per the terms of the policy, the Allowance must be repaid in full.

This allowance is intended, but not limited to the following:

- Travel expenses not covered by policy
- Temporary housing not covered by policy
- Commuting costs
- Additional income tax liability
- Express Mail Charges (Federal Express, UPS, Airborne Express, etc.)
- Notary fees
- Connecting utilities, TV antenna, etc.
- Concessions negotiated in the sale of a home
- Installation of major appliances
- Pet expenses: moving, kennel etc.
- Losses of fees for subscriptions, memberships, schools, safety deposit box
- Automobile registration fees, licenses, or smog control charges
- Spouse/Domestic Partner employment costs
- Tips
- Cleaning, trash/debris removal
- Purchase, alteration, installation of window and floor coverings
- Laundry and cleaning
- Personal telephone calls (long distance, cell phone charges)
- Child care expenses
- **Extra** pick-ups for removal of packing boxes, etc.
- **Extra** delivery charges for moves From/To more than one location
- Travel home on weekends
- Wine and wine cellar shipment

HOUSE HUNTING TRIP

HOUSE HUNTING TRIP

The expense outlined below will be reimbursed in connection with 2 House Hunting trips of 4 days/4 nights each.

The employee will be reimbursed for the following expenses for the employee, spouse/domestic partner and dependent children.

Travel:	Advance purchase coach airfare
Lodging:	PG&E designated hotel or equivalent
Rental car:	4 days plus gas
Meals:	\$75/day maximum for adults and children 16 years of age and older \$40/day maximum for children under 16 years of age
	Alcoholic beverages are not reimbursed
Ground transportation:.	If required, taxi.

Receipts required for all expenses.

ENROUTE EXPENSES (Final trip to new location)

The employee will be reimbursed for the expenses relating to travel expenses necessary to move the members of the family from the old to the new location.

Travel:	Travel for employee, spouse/domestic partner and dependent children Advance purchase, coach airfare
Lodging:	Up to 3 nights at a PG&E designated hotel. This lodging is meant to cover the night(s) the employee may not be able to stay in the former residence because household goods have been removed OR at the new location as they cannot yet move into the new residence
Meals:	Up to 3 days, at the maximum rates noted above. Alcoholic beverages are not reimbursed.

Receipts required for all expenses.

CORPORATE HOUSING

The cost of corporate housing for the employee will be provided for up to 6 months, as long as the employee is still financially responsible for their former residence. Corporate housing is unable to accommodate pets.

HOUSEHOLD MOVE AND STORAGE

PG&E will pay the cost to transport your household goods from your current residence to your new permanent residence. This includes full packing, unpacking, disconnecting, and reconnecting appliances to EXISTING wiring, and plumbing. Service to appliances applies only to those appliances that were moved.

The pickup of goods from only ONE location is authorized. Additional stops at pickup or delivery will be billed to you.

If you are unavailable for a pick-up or delivery and do not notify the movers in advance, any additional charges will be billed to you.

Items associated with an in home business are **EXCLUDED**.

Do not contact any moving company; this will be done through Relocation Services.

The assigned carrier will contact you to arrange for a survey of the goods to be packed and moved. When contacted by the carrier, be sure to inform them of items that require special handling (piano, shop equipment, large freezers, bulky items, etc.) or of any access problems (narrow or hillside roads, stairs, etc.).

DO NOT arrange insurance for the move or storage of your goods. This is provided by PG&E. Please be sure you declare the value of your goods. Should the value exceed \$50,000, inform the carrier AND Relocation Services so that additional insurance can be provided.

A minimum notice of 30 working days is required. During summer months and Christmas holidays, more lead-time is required. Weekend moves are **not** authorized. If you request a weekend or holiday move, the overtime charges will be collected directly from you upon delivery.

It is recommended that you or a member of your family be present during packing and loading to make certain that a complete inventory is made. Upon delivery, you should inspect your belongings WHEN they are unloaded and unpacked to be sure all items on the inventory are delivered. You should report loss or damage to the driver and note it on the inventory. Claims for lost or damaged items not on the inventory will be denied. All claims must be submitted **within 90 days** of delivery date.

It is also recommended that on the day of delivery you allow for minimum unpacking services. PG&E has defined these as setting up beds, hanging paintings and mirrors, and connecting lamps. This will allow you to settle in. The remainder of the unpacking can be scheduled for the next day. Be sure you discuss your unpacking needs and preferences before your move occurs. This will allow for proper scheduling.

PG&E pay the following expenses directly to the mover:

· Cost of packing, moving, and unpacking your household goods. Unpacking is defined as removing the packed articles from the box in the appropriate room and the removal of the packing material on the day of delivery. Unpacking does not include putting glasses and dishes on shelves or putting clothes in drawers.

Packing material **MUST** be removed on the day of delivery. Extra pick-ups for the removal of packing material are your responsibility.

- Cost of packing, moving, and unpacking your household goods. Unpacking is defined as removing the packed articles from the box in the appropriate room and the removal of the packing material on the day of delivery. Unpacking does not include putting glasses and dishes on shelves or putting clothes in drawers.

Packing material **MUST** be removed on the day of delivery. Extra pick-ups for the removal of packing material are your responsibility.

- Storage of your household goods for up to 60 days. Storage costs in excess of 60 days will be billed directly to you upon delivery. The cost to move the goods out of storage is paid by the company providing it is within one year of your date of hire. It is your responsibility to arrange for payment of additional charges with the movers. Be sure to verify what forms of payment are acceptable.
- Normal appliance service for washer, dryer, refrigerator, and freezer that were a part of the move. New appliances delivered by a different source are excluded.
- Portable spas will be moved as long as plumbing and wiring is disconnected prior to the move. This is an employee responsibility. If a crane is required to move the spa, you will be charged for this service.
- Automobiles-- **interstate moves only** (over 750 miles). Value must exceed the cost of shipment.

EMPLOYEE HOUSEHOLD MOVE INSTRUCTIONS

PACKING

At the time of packing you or someone you can rely on should be present to note the carrier inventory of goods and their condition. You should write in your exceptions (make reference to the carrier's item number) at the close of the inventory **before** you sign it. The same inventory will be used at destination to check complete delivery and condition. You again should note exceptions **before** you sign. Failure to note damage immediately may result in claims being denied.

Company policy calls for the carrier to pack all normal household goods. If, for any reason, you desire to pack particular items, ask the carrier to provide proper packing materials and containers. The company will pay for this material. Items that require SPECIAL CARE should be called to the attention of the movers. Regulations affecting carrier's responsibilities for goods you pack and unpack vary from state to state. Claims for loss or damage are more difficult to substantiate when you pack or unpack part of your shipment. Therefore, you are encouraged to allow the carrier to do the entire job.

UNPACKING

Unpacking is defined as removing the packed articles from the box in the appropriate room and the removal of the packing boxes on the day of delivery. This service does not include putting glasses and dishes on shelves or putting clothes in drawers. **Extra pick-ups** for the removal of packing material are not authorized. You may wish to unpack some articles. If you do, claims against the carrier for loss or damage may be more difficult to substantiate. Make sure the inventory shows which articles you will unpack before you sign it.

Allowing the movers to remove cartons and packing materials on delivery day will insure that these materials are recycled.

You or your representative must be present at the time of delivery and unpacking. It is YOUR responsibility to insure that all items delivered are checked off the inventory.

Goods will be placed in the area of the house that you designate. Beds will be assembled and mirrors attached to dressers.

PACKING AND PICK-UP DATES

Bedding, utensils, and clothing can be set aside for use on your last night and packed on moving day. After a date is agreed upon, the carrier is required to give reasonable advance notice of delay, if unable to comply.

DELIVERY DATES

At the time your move is arranged, a delivery spread will be fixed according to your request and the carrier's ability to comply. Shipments of less than 2,000 pounds may require up to 14 days to deliver.

DELIVERY

You or someone you can rely on should be present to check off each item on your inventory as it comes into your residence. Make note of damaged or missing articles on the driver's inventory **BEFORE** signing.

HOUSEHOLD APPLIANCES

The carrier will inform you which household appliances require special services for transportation. These may include washers, dryers, freezers, sewing machines, televisions, refrigerators, etc. Ice makers and portable spas must be **disconnected by you** prior to the day of the move. Appliances will be reconnected only to **existing** plumbing and wiring. Reconnecting icemakers and portable spas is not authorized.

When portable spas are moved, should the use of a crane be required to lift the spa, this cost will be billed to you.

BILL OF LADING

After your goods are loaded, the driver will give you a bill of lading, which is the contract of carriage as well as your receipt. Be certain the bill of lading shows the correct destination address and proper instructions for notice of delivery.

FAMILY PETS

The company does not reimburse for the shipment of household pets. You must arrange for boarding, handling, shipping, insurance, shots, health certificates, etc. Your Cash Moving Allowance can be used for these expenses.

CARS

You are expected to drive your personal car to the new location. However, for **interstate** moves, the shipment of a maximum of two cars may be authorized provided the distance is greater than 750 miles. The value of the vehicles authorized to be moved **MUST EXCEED** the cost of shipment. Do not pack household or personal affects in a vehicle to be shipped. The carrier cannot be responsible for their loss or damage. Automobiles are insured at Blue Book value. Automobiles are not stored.

Please plan the move of your automobiles in advance. Cars may be shipped prior to the move of your household goods. Advance planning can eliminate the need for rental cars.

When accepting delivery of a car, check the car thoroughly for damage. Be certain to check under the hood and the undercarriage for damage. If damage is not reported **IMMEDIATELY**, claims may be denied.

Motorcycles and power mowers can usually be shipped with household goods. You must drain gas and oil.

STORAGE LOCKERS

The move of household goods from public storage lockers is authorized provided an extra stop is not required. Goods will be packed and loaded from only one location. If goods are picked up from a storage locker, the employee must contact the storage facility and arrange for all the necessary releases/documentation. You or your representative must be present to sign the inventory.

CHARGES

The company instructs carriers to bill for packing, moving, unpacking, and in-transit storage when authorized. You will be billed directly by the carrier for additional shipments and services, which you arrange. Unless you have been extended credit prior to delivery, payment for services you arrange must be by cash or certified check.

STORAGE

If possible, you should select new quarters before your household goods arrive so they can be delivered directly. If you have not arranged for new quarters by the time the goods arrive, in-transit storage may be authorized. You may be eligible for in-transit storage at a company-authorized facility provided the need does not arise because of your personal delay (e.g., vacation, enroute) in selecting quarters. Delivery out of storage may be authorized. If you elect to store your goods for a period longer than covered by the relocation policy, you will be billed for the additional storage and insurance costs (COD) when the goods are delivered.

Should a portion of your goods be delivered to a temporary location and the rest put in-transit storage, you will be responsible for the cost to move the goods from the temporary location.

Storage for longer than one year requires company approval.

ITEMS NOT AUTHORIZED TO BE MOVED

The following items are not authorized either due to company policy or legal restrictions placed on the movers.

- Building material: bricks, rocks, gravel, lumber, cement, etc.
- Combustible items: paint, lighter fluid, aerosols
- Plants, shrubs, trees, fertilizer, dirt
- Perishable foodstuffs and/or frozen foods
- Pets or animals of any kind
- Boats, boat trailers, recreational vehicles, trailers
- Valuable jewelry, precious stones, furs
- Valuable papers, securities, money
- Ammunition and/or explosives
- Tractors or farm implements other than those required for normal garden use
- Firewood, coal
- Articles of inherent or extraordinary value
- Farm animals, horses, cattle, fowl, etc.
- Items from a temporary residence
- Items that cannot be attached a value (personal paintings, pottery, etc.)
- Auto parts
- Autos that cannot be driven
- Satellite dishes
- Wine and wine cellar shipments

SERVICES NOT AUTHORIZED

The following services are not authorized.

- Storage of automobiles
- Weekend or holiday moves, overtime
- **Extra pick-up and/or delivery**

- Disassembly and reassembly of playhouses, tool sheds, swimming pools/spas, TV antennas, satellite dishes, workbenches, play equipment
- Installation of television antennas, tool sheds, play equipment, etc.
- Removal of wall-to-wall carpeting and/or draperies
- Providing or moving electrical/gas outlets for appliances
- Disconnecting/connecting ice makers or portable spas
- Venting dryers
- Reconnecting water softeners
- Draining and refilling waterbeds
- Moving items from a temporary living location
- Storage of household goods, other than in-transit
- Extra pick-up for removal of packing material
- House cleaning
- Exclusive use of a van to expedite service
- Crane service for a spa

INSURANCE

The company has arranged for insurance coverage of personal property shipped and/or stored by the company-approved household goods carriers.

PG&E provide insurance (full replacement value) for household goods up to \$50,000. Automobiles authorized for interstate moves are insured at Blue Book value. If the estimated value of goods exceeds \$50,000, you must declare full value of your household furnishings to the carrier and Relocation Services so that additional coverage can be provided.

NOTE:Movers will accept items such as televisions, stereos, personal computers, recording equipment, and other similar items for shipment. However, they will not accept liability for internal damage to the equipment or appliances caused by moving, vibrations or other normal handling. They will only accept liability for damage when there is EXTERNAL VISUAL DAMAGE caused by maltreatment and the condition of the item is noted at the time of delivery.

You must carry with you such articles as money, valuable documents, credit cards, jewelry, watches, firearms, live plants, etc. Carriers cannot insure these articles. **You should transport irreplaceable articles** . Settlement of claims requires **that damaged goods be surrendered** to the insurance company when a replacement is provided.

All claims for loss or damage to Household goods should be submitted directly to the insurance company. Claims for damage to your home should be submitted directly to the carrier.

ALL CLAIMS MUST BE SUBMITTED WITHIN 90 DAYS OF DELIVERY.

ARTICLES OF VALUE

Articles of sentimental value, documents, jewelry, family portraits, photo albums, stamp and coin collections, birth certificates and diplomas are examples of articles that fall into this category. The company will NOT assume responsibility for safe movement of such articles.

HIGH VALUE ARTICLES

Antiques, heirlooms, rare book and art works or items with difficult to establish value fall into this category. In order for the company to assume responsibility for high valued articles, you **MUST** list them and declare their value. You **MUST** be able to verify the value claimed with purchase documents or current professional appraisals. If you must have items appraised to establish value, it will be at your expense. If you are unable to verify the declared value, claims will be settled on the basis of the utilitarian value of the item.

IMPORTANT HINTS

- Be certain your new residence can accommodate the furniture you are moving. Measuring the rooms prior to moving can help you determine whether or not all furniture should be transported. If not, you may want to dispose of it at your old location.
- Be certain the movers can contact you on the day of the move by providing them with a cell phone number.
- Keep the telephone number of the movers handy on moving day. You may need to contact them during the move or during delivery.
- Leave a message telephone number with the movers. It may be necessary to contact you during the move or prior to the delivery of goods.
- Notify the driver or movers **IMMEDIATELY** of any damaged or missing items. to report damage or missing items immediately may result in claims being denied.

Items not usually considered to be normal household goods and those not suited to furniture van transport are excluded; these include but are not limited to large machinery, boats, recreational vehicles, plants, building materials, frozen food, items related to a home business, and items which cost more to ship than the value.

SELECTING A REAL ESTATE AGENT

Program guidelines require you to work with agents from an approved list to list your home.

As a new hire your time is very valuable-you have a LIMITED amount of time in which to complete house hunting and get settled in your new location. For this reason, if you are not satisfied with the service your real estate agent is providing, do not hesitate to request another agent. Although you may feel obligated to the first agent because they have spent time showing you homes, you do not owe them anything.

PG&E REALTOR NETWORK

The home purchase firm and PG&E have created a list of preferred real estate agents to assist employees in obtaining quality service.

The home purchase firm or PG&E's Relocation Department will automatically refer an employee to a preferred agent in the new location.

ADVANTAGES TO YOU

It is common practice in the real estate industry for a real estate broker in one community to refer a prospective homebuyer to a real estate agent in another community. Then if the homebuyer is successful in buying, the broker who receives the homebuyer as a client pays a "referral fee" to the broker who gave the referral.

Unfortunately, in most cases a real estate broker refers the homebuyer to a broker in another area or state who is UNKNOWN to the broker. Usually the only criteria the selected broker had to meet was that he/she was listed in a national book of brokers willing to pay a referral fee.

On the other hand, because the home purchase firm and PG&E list homes with real estate firms all over the country every day they are in an ideal position to evaluate the professionalism, track record and quality of services offered by different firms. As a result, the real estate brokers in the "PG&E" network are screened professionals who are knowledgeable about residential real estate transactions AND the special needs of corporate new hires. This is VERY IMPORTANT because a broker who is not knowledgeable or professional can seriously hinder your purchasing efforts.

In addition, the home purchase firm and PG&E continually monitor the performance of these brokers. The brokers realize that in addition to serving the new hire needs, they are working for PG&E as well. As a result, the brokers in the network will be attentive to your needs so they can be assured of continued business.

It is critical that you have a knowledgeable real estate broker when looking for a home in your new area. You will need to rely on the broker to show you where schools and amenities are located, explain what home values are doing in different areas, and possibly give you guidance regarding what types of homes traditionally have a shorter marketing time.

The brokers in the network will be thoroughly familiar with the area where you will be house hunting. Should you decide to house hunt in an area unfamiliar to the broker, he or she will refer you back to the home purchase firm so you can be referred to a broker that is familiar with that particular area.

They can also offer some guidance regarding home values in an area by showing you sales prices of comparable homes that have recently sold. Unfortunately, IT IS NOT unusual for an “out-of-town” buyer to overpay for a home if the buyer has moved from an area of higher priced homes and the broker does not take time to show the buyer what similar homes sold for.

The firms and brokers in the network have demonstrated that they can help you find a home and neighborhood that is right for you. They have done this by joining professional organizations that educate brokers on the specific needs of corporate new hires.

Along with the definite advantages to you, the network offers advantages to PG&E as well. If you buy a home through a network referred real estate firm, that firm will pay PG&E a “referral fee”. This revenue will then be used to offset relocation expenses to PG&E. And because the costs to relocate employees is high, it makes good competitive business sense to take advantage of the opportunity to reduce expenses whenever possible.

As a final point, it is important for you to know that the payment of a referral fee does not affect the price you pay for a home.

FOR THESE REASONS, ALL RELOCATING NEW HIRES ARE REQUIRED TO USE THE HOME PURCHASE/PG&E BROKER REFERRAL NETWORK WHEN SELLING AND/OR BUYING A HOME.

Employees who are not currently home owners or employees who do not participate in the Home Sale Assistance Program should contact call Relocation Services to request a referral.

HOUSE HUNTING TIPS

Some of the following suggestions may aid you in your search for a home in your new location.

- Be cautious if you are moving to a lower cost area. What may appear to be a bargain based on prices in your present location may be overpriced in your new location. New hires have a reputation for paying MORE for homes in their new location than someone who is already living in the area and is more familiar with the market. Look around enough to be able to judge local values.

This is where a PG&E approved real estate agent can be of value.
- When looking at homes, keep your top two or three choices in mind. In this way, when you begin negotiations on your first choice, you will have more leverage if they know you also have one or two more homes on which you are willing to make offers.
- If you are thinking about building a home in your new location, it may be advisable to reconsider. You will be in a new job, which may initially involve more time on the job and this, coupled with the demands and stresses of new home construction, may be a large burden.
- You should keep in mind that under current relocation policy investments in most improvements, personal property, etc. will not be protected - you will only be protected on the LESSER of the TRUE purchase price of the home or the appraised value established by the lender at time of purchase.
- If you anticipate being relocated again, you should strongly consider buying the home you want rather than buying a lesser home and making major improvements. ALWAYS THINK RESALE.
- You should ALWAYS make your offer to purchase contingent on
 - building inspections reports that are satisfactory, even if you are purchasing a newly constructed home
 - the property appraising at purchase price or higher
 - obtaining financing

HOME SALE ASSISTANCE PROGRAM

The Home Sale Assistance Program is an option available to help you sell your home for the best price given CURRENT MARKET condition. To achieve this goal, the home purchase firm will talk with you and the REALTOR to establish a list price and marketing strategy. If you are unable to secure a sale, you may elect to accept the Appraised Value Offer

The Home Sale Assistance Program is available if your home qualifies and if you abide by program guidelines. Mobile homes and homes owned with a non-Spouse/Domestic Partner are ineligible for this program. You must sign and return the Home Sale Assistance Agreement to initiate participation in the program.

Briefly, the program works as follows. Your home must meet program guidelines. You must inform Relocation Services within 7 days of your effective date of hire that you are requesting participation in the Home Sale Assistance Program and return a signed copy of the Home Sale Assistance Agreement. Relocation Services will then notify the home purchase firm of your interest and a consultant will contact you with details of the program, which includes:

- Prelisting Analysis and Strategy (Brokers Market Analysis) using an approved list of realtors
- Listing Price Recommendation and Approval
- The Appraised Process
- The Amended Value Program
- The Appraised Value Program
- Equity Advances

In order to participate in the program you may **not list** your home for sale until the prelisting analysis is completed and presented to you. After review of this data with you, a recommended list price will be determined. You may list your home prior to the appraisal process being completed. The initial list price is based on the Brokers Market Analysis. Once the appraisal process is completed, it may be necessary to adjust the list price since it must be within program guidelines. The current list price guideline is:

List price cannot exceed current listing guidelines.

The agents will complete the prelisting analysis and marketing strategy. You must list your home within the listing guidelines and actively market it for 45 days.

The purpose of the prelisting analysis is to acquaint you with current market conditions. It will enable you to make the best use of the time available to you to market your home, usually about 60 days. In today's market initial pricing is critical to securing a sale. While your home is on the market the appraisal process will also begin. Once the appraisal process is completed and the Appraised Value Offer determined your initial list price may require adjustment.

Failure to observe listing guidelines will disqualify you from the program.

INTRODUCTION

This Home Sale Assistance Program is designed to help you sell your home for the current market value. By using this service, you can receive your equity and move on to the new location. You will then be free to concentrate on your new job. This section outlines the PG&E Home Sale Assistance Program.

The goal of the Home Sale Assistance Program is to assist you in obtaining the highest possible price for your home in the current market. To achieve this goal, the home purchase firm will work with **you and your Realtor** to develop a marketing strategy and assist you to negotiate the highest price.

After negotiating a sale, DO NOT sign any document or accept any deposit. Contact your Consultant IMMEDIATELY. Signing any documents could jeopardize your participation in the program and favorable tax treatment.

Several documents must be completed and returned to the home purchase firm whether you assign an offer or accept the Appraised Value Offer. Your Consultant is available to assist you and your Realtor completes the necessary documents. Your transactions cannot be completed until the home purchase firm receives all required documentation.

PG&E reimburses the home purchase firm for the normal seller's closing costs associated with acquiring and selling your home. These include initial assessments (inspections), appraisals, as well as broker commissions. The home purchase firm receives a flat service fee from PG&E for providing these services.

It is not the home purchase firm's purpose to benefit from or make a profit on the sale of your home. Helping you get the best possible price for your home within a reasonable time is everyone's objective: Yours, PG&E's and the home purchase firm's.

AN OVERVIEW

You are allowed up to **seven days** from the date of hire to request this service from Relocation Services by returning the Home Sale Assistance Agreement to Relocation Services.

- Your Consultant will contact you to provide an overview of the program. This contact will occur within 48 hours of Relocation Services notifying the home purchase firm of your interest.
- Your consultant will provide you with a list of approved agents to select from.
- The agents will complete the Prelisting Analysis and Marketing Strategy PRIOR to listing your home. Spouse/Domestic Partners and family members are ineligible to list an employee's home. Two Broker's Market Analysis will be obtained.
- Upon review of this material with you, the home purchase firm will recommend an initial list price.
- Local independent appraisers selected by you from an approved list will appraise your home.
- Upon receipt of the Appraisal Value Offer, your list price must be within current program guidelines.
- Property assessments (inspections) appropriate to the age and condition of your home are required and will be ordered by the home purchase firm.
- The home purchase firm will extend an Appraised Value Offer to purchase your home. This offer is valid for 60 days.
- You may assign an offer or accept the Appraised Value Offer at any time during the 60-day marketing period provided your home has been listed for at least 45 days.
- You must present and review ALL offers with your Consultant even though they may be less or seem less than the Appraised Value Offer. This will assist you in determining which offer will net you the greatest amount. The review will also confirm which closing costs are reimbursable under the PG&E program.
- Once you assign an offer or accept the Appraised Value offer, you may receive an advance on your equity before the close of escrow for use as an earnest deposit/down payment on your new home. This advance is based on the Appraised Value Offer, not the sales price.

ELIGIBILITY

To be eligible for this program, your home must meet the following requirements:

- A completed typical single -family dwelling or condominiums on a standard size lot (less than **one acre**). Unusual homes such as geodesic domes, earth homes, log cabins, houseboats, A-frames, Victorians and other specialty homes are excluded.
- Homes older than 40 years may be ineligible. Exceptions may be made if the homeowner can provide a letter of code compliance (dated within the last 5 years) from the appropriate governmental inspection office.
- Your **principal** residence and where you **currently** reside
- Owned only by you and/or your Spouse/Domestic Partner (an ex-Spouse/ Domestic Partner or parent cannot be on the title)
- Determined to be marketable by PG&E
- Mortgage payments, Real Estate taxes, and Association dues must be current.
- Zoned residential. Rural residential zoning or lots larger than **one acre** do not qualify.
- All required building permits and private road maintenance agreements must be recorded

It is also important to note the following:

Your Listing Agreement must include the "Exclusion Clause."

- You must list your home and actively market it for at least 45 days.
- When you request the home purchase firm's assistance, your home must be available for sale. It cannot have been rented or leased within the prior 12 months. It **cannot** be rented or leased after you elect to participate. **All construction and/or repairs must be completed prior to requesting the Home sale Assistance Program .**

If upon appraisal and subsequent inspection, it is determined that repairs are required, you may either undertake and pay for those repairs OR allow the home purchase firm to order repair work and deduct twice the cost (except for termite work) from your final equity. Excess funds withheld will be returned upon completion of the work.

Major structural defects may affect the marketability of a home and may disqualify a home from the Home Sale Assistance Program.

- Homes containing UFFI, asbestos (interior or exterior), an unacceptable level of radon gas, or any other toxic substance are ineligible.
- Homes with LP siding or synthetic stucco are ineligible.
- Homes with toxic mold.
- Homes containing a well must have water rights. In addition, the water supply must be BOTH potable and ample under local standards.
- Farms, places of business, cooperative apartments, mobile homes, duplexes, vacation and income (rental) property are ineligible.
- The land on which the residence is located must constitute a lot of standard size for the area and be zoned residential. Land not reasonably necessary for the use and enjoyment of the property as a single-family dwelling, such as additional lots or farm acreage, is excluded.
- Condominiums must meet the following guidelines:
 - Only twenty percent (20%) of the total number of finished units can be vacant and/or unsold.
 - Only twenty percent (20%) of the units may be owned by absentee investors for rental purposes.
 - Association dues/Assessments per year (net of utilities) should not exceed two percent (2%) of the estimated fair market value of the condominium unit.
 - Condominium units in the complex must be mortgageable by FNMA standards.
 - Condominium Associations must be in sound financial condition as evidenced by (I) current financial statements, (II) sufficient replacement reserves, (III) no rapid increase association dues, and (IV) no unusual or excessive liens.

Your are responsible for providing verification of the above.

- Other factors which may affect the eligibility of a property for this program include, but are not limited to, the following:
 - Legal/title problems (liens, judgments)
 - Property line issues (properties with private roads must have a recorded road maintenance agreement)
 - Structural problems/damage

- Expansive soil
- Safety or code violations
- Unmarketable title
- Inability to meet conventional lender or insurance requirements
- Properties in foreclosure
- Bankruptcy
- Special financing (e.g., first-time buyers)

If your home is subject to any of the items listed above, inform Relocation Services.

- **PG&E RETAIN THE RIGHT TO MAKE THE FINAL DECISION ON THE ELIGIBILITY OF A HOME FOR THE HOME SALE ASSISTANCE PROGRAM.**

REQUIRED INSPECTIONS/DISCLOSURE

Pest and General Home Inspections are required for all homes. If you have a pool and/or spa that is being sold with the home, a pool/spa and equipment inspection is required. If the appraisers or pest inspector recommends a roof inspection, one will be ordered. If applicable, a septic system/well inspection, radon gas or any other inspections required to satisfy local codes will be ordered. In some cases, a structural or soil inspection may be ordered. All inspections will be ordered and paid by the home purchase firm. Copies of the reports will be provided to you.

Payment for any termite work (Section I and II), pool, spa, septic system, roof work and/or repair, as well as any repairs required by a general home inspection will be your responsibility. Re-inspection charges may be your responsibility. In the event a report calls for the further inspection of **inaccessible areas**, funds will be withheld in the event that repairs are required.

You may order the work done at your expense and submit the re inspection reports directly to the home purchase firm. Re inspection reports are required before final equity can be released.

Twice the amount of the estimate, except for termite repairs, will be withheld for the cost of repairs not completed prior to you vacating your home. Any refund will be forwarded to you with a revised closing statement after the work has been completed.

All repairs to correct any local code violations as well as damage, dry rot, etc., must be completed prior to you vacating your home. Permits required by the local government agencies must be on file.

Disclosure laws mandate PG&E and the home purchase firm to provide copies of all reports to potential buyers. The cost of repairs is not disclosed.

Employees are responsible for making **full** disclosure on their property. Any litigation resulting from improper disclosure will be solely the employee's responsibility.

YOUR OPTIONS

PG&E provides you with the following Home Sale Assistance options:

- Amended Value -- Sell your home to a buyer of your choice for a price that is equal to or more than the Appraised Value Offer and assign the offer to the home purchase firm who will coordinate the closing. Program guidelines must be followed.
- Appraised Value Offer -- Amend the offer and sell your home to the home purchase firm for the Appraised Value Offer.
- Sell your home without the assistance of the home purchase firm. You will be reimbursed typical seller's Closing Costs. When selecting this option, employees are encouraged to consider the tax consequences associated with this reimbursement.

LISTING YOUR HOME FOR SALE

To be sure you receive the best possible price for your home and to test the market value, it is recommended that you list your property with an approved REALTOR. For maximum exposure, insist upon a multiple-listing agreement of no more than 60 days.

To provide for cancellation of the listing agreement should you accept the home purchase firm's offer, the listing agreement **must** include the Exclusion Clause.

WITHOUT THE EXCLUSION CLAUSE IN YOUR LISTING AGREEMENT YOUR HOME CANNOT QUALIFY FOR THE HOME SALE ASSISTANCE PROGRAM. A COPY WILL BE PROVIDED BY THE HOME PURCHASE FIRM.

Your listing agreement must be in writing. For your own protection, leave no blanks and be sure to insert the exclusion clause before signing any listing agreement.

Should you encounter any difficulty in having your listing accepted with this provision, call your Consultant immediately. Your Consultant can usually address the Realtor's concerns with a phone call.

If an employee, Spouse/Domestic Partner, or family member is a REALTOR, it is a conflict of interest for the company to reimburse members of a relocating family for services (commission) connected with the sale of the old home or purchase of a new home.

MARKETING TIPS

The home purchase firm has a great deal of knowledge and experience in the real estate market. They understand that a home is often a family's greatest single asset.

To obtain the best price within the time limits of your relocation, the following steps are recommended:

Before you list your home at a specific asking price, spend a few hours with a REALTOR, touring your community and examining recent comparable sales as well as current listings. By doing this, you will be viewing your home in the same competitive arena as a potential buyer.

The prelisting Broker's Market Analysis required by PG&E will provide you recent price and other information about comparable homes in your area that have sold and closed. This information will assist you in knowing the competition and in arriving at a REALISTIC and COMPETITIVE list price.

Pricing realistically in relation to your specific market is critical. Local REALTORS will be able to market your home more effectively if it is priced correctly. Homes sell best when they are properly priced for the specific marketplace.

In estimating value, potential buyers and appraisers consider the condition of your home. Not surprisingly, a well maintained home has greater buyer appeal. If you have any deferred maintenance, you will want to complete it to make your home as marketable and competitive as possible.

Start the appraisal process as quickly as possible. You'll be able to price your home realistically in relation to the market.

THE APPRAISAL PROCESS

The appraisal process establishes the Probable Sale Price of your property based on two appraisals. This procedure requires approximately 15 working days. Should a third appraisal be required, the process will take longer. Once the home purchase firm has been notified by PG&E of your request to participate, your Consultant will call you within two business days to arrange for your home to be appraised. At that time, you will be provided with names of appraisers. You will be asked to select two, plus an alternate. The alternate will be used if one of the original two is unavailable or if a third appraisal is required. You must notify the home purchase firm of your selections as soon as possible, but no later than **two** weeks after receiving the names.

After you have selected appraisers, the home purchase firm will contact them with instructions to call you as soon as possible to arrange an appointment to appraise your home at a mutually convenient time. You should schedule the visits of the appraisers for different times. Allow at least two hours between appointments. If you have any special timing problems in connection with the appraisal of your home, your Consultant can make this fact known to the appraisers at the outset. The home purchase firm is required to notify PG&E of any delays.

The appraisers are independent professionals, experienced in the valuation of properties in your neighborhood. Appraisers are selected by virtue of their demonstrated qualifications and past performance. The home purchase firm must receive the written report establishing an anticipated sale price within ten business days of inspecting your home. It will take the home purchase firm 3-4 days to review the appraisals.

Who Are the Appraisers?

First, the appraisers are designated professionals who specialize in appraising residential properties. Second, they are independent fee appraisers.

The home purchase firm selects and lists appraisers after careful screening for experience, professionalism, and accuracy. Appraisers are evaluated through continuous monitoring of their performance.

HOW THE APPRAISAL PROCESS WORKS

Homes are purchased on a comparative basis. Buyers shop the market, comparing available homes and seeking the best values. A home must be **REALISTICALLY** priced in order to sell. Overpriced homes normally do not sell and soon become overexposed, making a sale difficult. In order to establish a realistic price range, it is essential that the market value of your property be accurately determined. The first step involves engaging qualified, independent, professional appraisers to inspect and evaluate your property.

What Is an Appraisal?

An appraisal is a carefully derived estimate of market value, as of a specific date, based on a logical study of the local real estate market, the condition of the property, financing conditions, and other general and specific data that are currently in effect or will most likely occur within a marketing period of 90-120 days (list to close).

What Is a Market Value?

Market value is defined as "an estimate of the price to be paid for a property by a well-informed buyer based on current and forecast market trends." It represents the most accurate means available for projecting what a home will sell for on the open market.

How Appraisers Estimate Value

To arrive at a market value estimate, an appraiser must consider both general and specific data as well as the comparison of similar homes. General data includes regional, city, and neighborhood information and incorporates physical, economic, social, and political factors that may influence property value. Specific data pertains to the property itself.

GENERAL DATA

- Supply and Demand

The number of people buying homes and the number of homes on the market affects property values. However, if a sellers' market or buyers' market exists in a particular neighborhood, it does not necessarily follow that the same condition is true elsewhere. In appraising your property, the appraiser will consider local supply and demand. How many homes are for sale in your immediate neighborhood? How quickly are they being sold? What are the conditions surrounding the sale?

- Location

The general condition of homes in your immediate neighborhood and accessibility to shopping, schools, and transportation are key factors. Proximity to heavy traffic, commercial establishments or industrial zones can adversely affect property values.

- Economic Conditions

Economic conditions vary from region to region. Strikes, plant closings, foreclosures, and outgoing group moves can have a depressing impact on property values. However, new plant openings, incoming group moves, or locally awarded contracts can have an uplifting effect.

- Financing Conditions

The cost (interest rates, discount points, etc.) and availability of mortgage financing both have substantial impact on housing prices. If financing is costly or scarce, the market value of your home may be favorably affected if it has a high balance assumable mortgage with a low interest rate.

- Political Factors

State and local governments can affect property values. school bonds, zoning changes, property reassessment, new school appropriations, as well as taxes and education, all impact housing prices.

SPECIFIC DATA

After collecting general data, the appraiser next analyzes a number of relevant specifics. If the inspection appears to move along at a relatively rapid pace, remember an appraiser is an informed professional whose trained eye misses little.

- Condition Viewed From Outside Your Home

Does your property have "curb appeal"? On first seeing your home from the street, what will a prospective buyer think? Does the general condition of the home and lot contribute to the home's attractiveness? Is there demand for your architectural style? Is your home on a public or private street? Is the street paved? Does it have a sidewalk? Does your community have a public water supply, a sewage system, or does it depend on a well or septic system?

- Condition Viewed From Inside Your Home

On entering your home, what will a prospective buyer think? This is especially true in a Buyer's market. Does the overall condition reflect pride of ownership? Does the floor plan afford a satisfactory flow of traffic? Is the closet space adequate? Is the kitchen spacious and up-to-date? Is the decor neutral or is it too personalized? The appraiser will record number of rooms, bedrooms, baths, kitchen, dining room, family, or similar rooms, and the dimensions of each. The appraiser will closely observe quality of construction, floor coverings, paint, wallpaper, age, type, and condition of kitchen appliances and anything else that reflects the overall condition of your home.

Appraisals are affected by many factors: a fireplace, lot size, topography, a garage "under" versus one that is attached or detached, a screened porch as opposed to an open deck, a swimming pool, tennis court, and even the electrical system (ample circuits for anticipated demand). Method of heating as well as energy savers such as insulation are significant factors in today's environment.

COMPARISON WITH SIMILAR HOMES

Comparable Sales

An appraisal is not complete unless your property is compared with similar homes that have recently sold and closed. Comparable sales analysis is one of the most important elements in a professional appraisal. Appraisers use a comprehensive data bank of homes to find satisfactory comparables. Individual properties that are substantially different are difficult to compare.

The appraisers are instructed to select at least three comparable properties for comparison. Each would ideally be in the general neighborhood of the appraised home, similar in size, style, and construction, and sold within the last three or four months. Such criteria cannot always be met. If the criteria cannot be met, the appraiser will make every effort to find the best comparables.

Appraisers make adjustments to compensate for any differences which significantly impact market value such as date and terms of sale, location, or architectural style of the home. Adjustments for improvements reflect the appraiser's estimate of the market value rather than the original or replacement cost. Certain improvements may not be valued as highly by prospective purchasers as their cost would indicate.

A property may be over improved. Your landscaping may be superior to that of your neighbors. You may have a cabana and swimming pool. However it is often difficult to sell a house for \$150,000 in an area of \$100,000 homes. Along the same lines, your decor may be unique and could have limited appeal. The appraiser is asked for an opinion, "Will this property sell without any qualifications in its current condition?"

The offer the home purchase firm extends is the result of a thorough review of the appraisals to ensure completeness, accuracy, and consistency. Only then will the appraisers' market value estimates be averaged to determine your Appraised Value Offer.

Because home selection is a highly personal and subjective process, an appraiser's estimate may be higher or lower than the eventual sales price. Nevertheless, the market value represents the most accurate means available for projecting what your home will bring on the open market.

Comparable Listings

The appraiser also reports on current listings in a comparable price range being offered in the marketplace. These homes are indications of what the market will bear in your neighborhood. Competitive listings have a bearing on the marketability of your home as well as what competition exists and must be considered when computing an opinion of value.

Competitive listings should be a significant factor when you are establishing a realistic list price for your home. This is especially true in an “over supplied” market.

In short, the appraisal will reflect the "as is," "as vacant" condition of your home on the day of the appraisal. Therefore, any deferred maintenance should be completed **prior** to appraiser's visit. Have your home in prime "show condition."

Points to remember about an appraisal and the marketplace:

- Money spent on repairs and maintenance is not normally recovered when a home is sold. Deferred maintenance, however, can actually reduce property value by the cost of needed repairs.
- If construction costs have risen, such an increase in value may be offset by other factors such as aging, wear or deferred maintenance.
- There is NO guarantee that a homeowner will make a profit when they sell their home; the MARKETPLACE is what determines whether a profit will be realized.
- With UNLIMITED TIME, a seller may be able to find a buyer willing to pay more than the appraised value. A relocation appraisal ESTIMATES the price which is most likely to be agreed upon by a typical buyer and seller within a reasonable period of time (90 to 120 days).
- The improvements you make to your home may NOT be considered as desirable by subsequent owners as they were by you. Improvements may not increase the value of your property by as much as they cost.
- Improvements or additions to a home do not necessarily increase value as much as their costs because an improvement that appeals to one owner may not appeal to all.
- When people have styled a home in a very personal way, they tend to place a high value on it. It can be difficult to understand that this personal touch does not necessarily translate into dollar value in the marketplace.

APPRAISAL INPUT

You may participate in the appraisal process. Please complete the Appraisal Worksheet form using homes **similar** to your own that have recently **sold** and **closed**. You may find the assistance of your REALTOR helpful in obtaining such information. Please give this information directly to each appraiser (with a copy to your Consultant) when he/she visits your home.

How the Offer is Calculated

Upon receipt of the written appraisals, they will be reviewed for any discrepancies. Following this review, the Appraised Value Offer will be established by averaging the two appraisals. If the difference between the two appraisals exceeds 5 percent, a third appraisal will be requested. The Appraised Value Offer will equal the average of the two closest appraisals.

BROKERS' PRICE OPINION

Although not part of the formal appraisal process, two Brokers' Market Analysis will be ordered. The information in these opinions will provide additional information to you and to the home purchase firm. Included will be marketing strategies and recommendations on how to make your property more competitive.

The Brokers asked to provide this information may also be responsible for ordering any professional inspections regarding the physical condition of your home (pool, roof, septic, etc.).

The Brokers' Price Analysis are not used to compute the Appraised Value Offer.

AMENDED VALUE PROGRAM

Any offer you receive must be reviewed with your Consultant. Should you wish to assign it, **DO NOT** sign any documents. Call your Consultant with details of the offer. This review will ensure that the terms you agreed to are indeed covered by the PG&E policy. Your **Consultant** will sign the offer as your nominee in order to protect favorable tax treatment of the program. **CONTINGENT OFFERS DO NOT QUALIFY FOR THE PROGRAM** .

As part of the assistance, PG&E pays your brokers' commission and customary seller's closing costs (Customary for the county will be as defined by local Title Company. Concessions are not considered customary.) The customary costs of sale will not appear on the closing statement. If you assign the closing of the sale of your home to the home purchase firm, you should not submit a closing statement to PG&E for reimbursement.

When you assign an offer, you are financially responsible for your home until you vacate.

Should you assign an offer and permit the buyer to assume your loan, you must indemnify (in writing) both PG&E and the home purchase firm against any future default.

Amended Value Offer

- Your presence at the closing is not required since the home purchase firm will close the sale on your behalf. You and your family are free to move to your new location. You need only to sign the sellers' closing instructions, the deed and other related documents.
- When you assign an offer, you will not incur normal selling expenses and will not, therefore, require reimbursement from PG&E.

You may assign more than one offer, that is, a backup offer to the home purchase firm. Make certain that you contact your Consultant for details beforehand.

APPRAISED VALUE OFFER

Accepting the Appraised Value Offer

Approximately 15 business days after the appraisals have been completed and thoroughly reviewed, your Consultant will call you with the Offer to purchase your home. An Offer to Purchase Package containing all the forms required for you to sell your home to the home purchase firm will follow.

Building permits must be on file to meet all current local building code requirements.

60 Day Marketing Period

Beginning with the day you are called with your Offer, you have 60 days to:

1. Find a buyer willing to purchase your home at a comparable or higher price than Appraised Value Offer, and turn the sale over to the home purchase firm for closing (Assigned Sale); or
2. Accept the Appraised Value Offer.

The 60-Day Market Period will not be extended for any reason.

You may accept the Appraised Value Offer anytime during the 60-day period by completing the appropriate documents. Your home must have been on the market for AT LEAST 45 days prior to accepting the Appraised Value Offer.

60 Day Vacate Period

Upon your acceptance of the Appraised Value Offer, you will have up to 60 days to vacate your home. You will be asked to indicate on the Seller's Data Sheet the date you plan to vacate.

Once you accept the Appraised Value Offer, your home will be listed for sale by the home purchase firm. You are expected to cooperate with the home purchase firm by allowing prospective buyers to view your home by appointment at reasonable hours.

You are responsible for all expenses of your home until the vacate date.

All appliances, heating, plumbing, and other fixtures to be sold with the home should be clean, in working order, and remain on the premises. If removed, the full replacement value for each will be withheld from your final equity.

PAYMENT OF EQUITY

In order to meet your new home purchase obligations, you may find that you need funds (equity) prior to the normal equity payment date (close of escrow). If so, payments of two types are available.

One : From the time your are informed of the Offer to the time you accept the offer or assign an offer, you may request an equity payment. This payment is available to you without any obligation to accept the home purchase firm's offer or assign an offer but must be repaid to the home purchase firm prior to the expiration of the offer period if you elect **not** to participate. To obtain this payment, contact your consultant and complete the Equity Advance agreement/Promissory Note.

Two : After assigning an offer or accepting the Appraised Value Offer, you may request an equity payment to be sent directly to your escrow account. This payment is limited to the **lesser** of (1) the amount required to purchase the new residence or (2) 98 percent of your equity based on the Appraised Value Offer computed to the Date of Possession. If you have an assigned offer, the equity is based on the Appraised Value Offer and not the assigned offer. This procedure is used to protect you against an over advancement of funds.

Your final equity is computed by deducting the following items from the sale price:

- Unpaid balance of principal and prorated interest on any mortgage(s) or equity line(s) of credit
- Proration of real estate taxes
- Unpaid special assessments, homeowner association dues
- Monetary liens, judgments
- Twice the estimated cost of work/repairs (except for termite repairs) if the work is not completed prior to your being cashed out.

Excess funds are withheld to eliminate any underpayment on your behalf. Excess deductions are returned to you at the time of final closing, after the work/repairs have been completed and satisfactory inspection reports have been obtained.

Please note: Equity **advances are made only to escrow accounts** .

All required repairs must be completed. Any costs PG&E incurs to return your home to clean, marketable condition will be subtracted from your final equity payment. To prevent this, please discuss with the Realtor during the walk through those items that require repair and complete those repairs yourself. Final equity may be withheld pending firm bids for any needed repairs.

If you accept the Offer, the home purchase firm will take over responsibility for the home on the Date of Possession. Gas, electric, and water service should be left on. You should request a final reading and ask that a final billing be sent to you. The home purchase firm will arrange for a local REALTOR to have these utilities billed to them when you vacate.

The home purchase firm will provide insurance coverage for the home effective on the contract or vacate date, whichever is later. You are responsible for maintaining coverage until then and for obtaining any refund due you from the insurance company. If you have flood insurance, discuss the transfer process with your Consultant.

FINAL EQUITY PAYMENT

Your final equity will be sent to you as soon as the home purchase firm receives all of the required documents including your executed deed package. Equity is calculated by prorating the carrying expenses listed below and subtracting them from the Appraised Value Offer.

Carrying Expenses :

1. Outstanding encumbrances and/or indebtedness against the property and prorated interest;
2. Prorated property taxes;
3. If the required work is not completed and re-inspected prior to your vacate date, twice the amount of the estimate (except for termite repairs) with be withheld to prevent any underpayment. Any excess funds will be refunded upon completion of the work; and
4. Bonds and assessments where included in the appraised value but unpaid.

THINGS YOU NEED TO DO

Call your consultant whenever you have a question.

Do not list your home with a local REALTOR until the Prelisting Analysis has been completed and approved. Be sure to include the "Exclusion Clause."

Return the following to the home purchase firm from the introductory package.

- Power of Attorney
- California Real Estate Disclosure Statement
- All parties whose names appear on the Deed must sign this form. The Appraised Value Offer cannot be released until these documents are received by the home purchase firm.

Return the Statement of Loan Account to your lender(s) as soon as possible. Receipt of this information will expedite the calculation of your equity for any equity advance you may request.

It is helpful to telephone the lender and verify the address to which the request should be sent. Sending this request to the attention of the person you speak with may help speed processing. Having a contact name will assist you should you need to follow up.

Scheduling Appraisers/Inspectors Visits

The appraisers you select will contact you to schedule an appointment to visit your home. This contact should be made within 48 hours of your making your selection known to the home purchase firm. Contact your Consultant immediately if this does not occur. If both visits are scheduled for the same day, allow at least 2 hours between appointments. Have your Appraisal Input form completed and provide a copy to each appraiser.

Payment of Equity

Five working days must be allowed to process your request. Advances can only be made to escrow accounts. A maximum of 98 percent of your equity (based on the Appraised Value Offer) can be advanced.

Final Walk through

Contact the local REALTOR assigned by the home purchase firm to arrange for the final walk through (on the day you vacate). Keys may be given to the REALTOR at this time. This process is required for Appraised Value Sales only.

Final Utility Bills

Discuss the transfer of utilities with your consultant. DO NOT DISCONNECT SERVICE.

Insurance

Cancel your homeowner's policy and ask your insurance agent to forward any refund directly to you. If you have flood insurance, discuss the transfer process with your Consultant.

New Mailing Address

Provide your new mailing address AND telephone numbers to your Consultant.

VACATING YOUR HOME

Before vacating your home, contact your Consultant. A local REALTOR assigned by the home purchase firm will conduct a final walk through prior to the release of final equity. The walk through should be done on the date you vacate your home.

When you vacate, your home should be left in **broom-clean** condition and in the same condition, ordinary wear and tear excepted, as on the day your home was appraised. Under PG&E's policy, the costs to put your home in broom-clean condition (clean oven, clean basins, floors, etc.) will be withheld from your final equity.

*****Next two pages contain Realtors walkthrough checklist

PG&E
Realtor's Final Walk Through Checklist
Instructions to Realtor

This form is to be completed by the Realtor on the final walk through. Both the Realtor and PG&E employee must sign off on page 2 of this report. Please make a (✓) next to the items that are inspected and in good condition. Use the comments section to note any items which need repair, replacement or are not in “broom-clean” condition. Also note in the comments section any furniture/appliances which obstruct your inspection of an area.

PROPERTY ADDRESSPG&E EMPLOYEE	
(✓)	LIVING ROOM WALLS DOORS FLOOR/CARPET WINDOWS/SCREENS COVERINGS LIGHT FIXTURES FIREPLACE/WOOD STOVE OTHER
	COMMENTS
(✓)	DINING ROOM WALLS DOORS FLOOR/CARPET WINDOWS/SCREENS COVERINGS LIGHT FIXTURES OTHER
	COMMENTS
(✓)	KITCHEN WALLS DOORS FLOOR WINDOWS/SCREENS COVERINGS LIGHT FIXTURES STOVE TOP OVEN(S) HOOD/FAN DISHWASHER TRASH COMPACTOR COUNTERS GARBAGE DISPOSAL REFRIGERATOR OTHER
	COMMENTS

HOME SALE DIRECT REIMBURSEMENT

While PG&E has retained the home purchase firm for your benefit and convenience, you do not have to accept the Appraised Value Offer nor are you obligated to assign an offer to the home purchase firm for closing. If you decide to close a sale on your own, you may be reimbursed by PG&E under the Home Sale-Direct Reimbursement policy. Some tax assistance is provided. See Tax Summary. A list of the most typical seller closing costs can be found on page 41.

Employees who select this option are encouraged to review the potential tax consequences with Relocation Services.

REIMBURSEMENT FOR CLOSING COSTS (NEW HOME)

PG&E will reimburse you for the **customary** (as defined by local title company) closing costs paid by the buyer in your new area with the following limitations: the LESSER of actual costs covered by policy or two and one-half (2.5) percent of the purchase price of your new home. Tax Assistance is provided. Points are excluded from tax protection. See Tax Summary. Some items have a dollar limit. See the worksheet in your packet for this information. Concessions in a buyer's market are not considered customary. One hundred percent equity reinvestment is assumed. Ownership with other than a Spouse/Domestic Partner may not qualify for this assistance. Consult with Relocation Services.

Note: Credits from the seller will be deducted from the reimbursement.

In addition to this limit a home inspection is required and is not subject to 2.5% limit.

You must be a homeowner at the time of hire to be eligible for this assistance. A list of customary reimbursable items appears on page 43. You have one year from the effective date of hire to request reimbursement.

Remember to plan to have the necessary cash available to cover closing costs as they are reimbursed after the close of escrow.

Interim financing for the construction of a new home is excluded from the program. Only the final loan is eligible for consideration. If you plan to construct a new home, you are encouraged to review the reimbursement procedure with Relocation Services. Employees who have a home constructed are limited to the same overall 2.5 percent maximum reimbursement. If you choose non-conventional financing consult with Relocation Services to determine your eligibility.

It is important to note that points are subject to withholding taxes and are not tax protected. However, they may be deductible for tax purposes as an itemized deduction. See Tax Summary.

TAXES

The sale of your former home and the purchase of your new home may have varying income tax consequences.

Most of the assistance outlined in this handbook may be considered taxable and must be reported to the Internal Revenue Service. Therefore, you will be taxed on it in the year in which it is **paid** by the company.

The Internal Revenue Service requires that taxes be withheld at the time of reimbursement. You are encouraged to review the TAX SUMMARY sheet to understand how the process is implemented.

We recommend that you keep receipts for ALL of your relocation expenses, even when not required by the company for reimbursement. These may be required as documentation by local, state, or federal tax authorities. We also recommend that you seek the advice of a competent tax professional to assist you in filing your taxes in the year that you incur relocation expenses. Your moving allowance may be used to offset the cost of this service. A chart summarizing how the company tax treats relocation expenses is provided in your packet.

In January of each year, Relocation Services will provide you with a Relocation Expense Summary. This information will assist you in the preparation of your annual tax return.

TIME OFF

The decision to grant time off from work for relocation related activities is a line decision and employees are encouraged to discuss this with their supervisor. The decision to grant time off with pay and the charge of time off with pay is up to the individual department.

USE OF COMPANY CAR

The IRS requires that use of a Company car for relocation related expenses be reported as imputed income. Consult with Relocation Services for details.

APPENDIX

HELPFUL HINTS WHEN BUYING OR SELLING A HOME

BUYING A HOME

Make several thorough tours of the home. Try to visualize traffic flow. Check to make sure there is adequate storage and closet space. Check the position of the house on the lot to see how much sunlight you can expect to receive. Look at the size of the rooms in relation to your furniture.

Investigate the neighborhood. If it is a new area, check to see if you will be assessed for new road, sidewalks, or schools. If it is an old area, check to see how well maintained the surrounding homes appear.

Beware of poor construction. Some indications of this are cheap fixtures, uneven floors, and doors that don't fit properly.

Carefully check the heating and cooling system. Make sure it can meet the demands of the climate.

Consider the distance from your job, from schools, and from shopping areas.

Do not be sold by "gimmick" items such as skylights or beamed ceilings, especially if the overall construction is not good.

Do not buy a home you are not sure you can afford. Remember that you must take into account property taxes, utilities, maintenance, and many miscellaneous expenses which may exceed your budget.

SELLING A HOME

Clean your house as thoroughly as possible. Make sure that all appliances, rugs, tile, and bathroom fixtures are clean. Get rid of clutter.

See that the price is right. An asking price higher than the market value can substantially reduce the number of potential buyers who will come to look at your home.

Trim the lawn and see that the grounds are neat.

Turn off the radio, stereo, or television when your house is being shown. They are distracting. Keep pets out of the way.

If your home is shown at night, turn on several lights throughout to create a feeling of warmth. If shown during the day, open curtains to make the house light and cheerful.

Do not apologize for the appearance of your home. After all, you're living in it!

Do not discuss furniture or interior decoration. This may confuse the buyer whose tastes are probably different from yours anyway.

Do not get involved in the conversation during the showing. Leave it to your Realtor to answer questions whenever possible.

CLOSING COSTS ASSOCIATED WITH THE SALE OF A HOME

1.REIMBURSABLE ITEMS*

Attorney fees (in lieu of a title company)
Brokerage fee/commission (normal for the area if a broker is used)**
City report
Escrow fees
Home warranty
Notary fees
Prepayment penalty on first mortgage***
Reconveyance fees
Recording fees
Statement fees
Tax stamps
Title insurance
Transfer tax (city and/or county)

2.NON-REIMBURSABLE ITEMS

Any items not specifically covered by policy or negotiated between buyer and seller
Appraisal fee
Assumption fee
Bonds
Buy downs
Credit reports
Delinquent taxes
Document preparation fee
Endorsements
Fix-up expenses and maintenance costs
Homeowner Association dues or transfer fees
Impound accounts
Insurance
Interest
Late charges
Mortgage insurance
Photos
Points of all kinds
Prepayment penalty on second mortgage
Principal
Reinspections
Repairs

2.NON-REIMBURSABLE ITEMS - continued

Taxes
Termite inspection
Termite/pest control work
VA/FHA points

*Consult with Relocation Services for customary items in the county of the sale.

**If an employee, Spouse/Domestic Partner or family member is a REALTOR, it is a conflict of interest for the company to reimburse members of a relocating family for services (commission) connected with the sale of the old home or purchase of a new home.

***Limited to the lesser of six months interest or \$3,000.

CLOSING COSTS ASSOCIATED WITH THE PURCHASE OF A HOME

1.REIMBURSABLE ITEMS*

Appraisal fees
Assumption fee
Attorney fees (in lieu of escrow fees, if typical for the area)
City report
Credit report (Limited)
Documentation preparation fees (Limited)
Endorsements
Escrow fees
Flood Certificate (Limited)
Forwarding fees
General Home Inspection
Home warranty
Loan tie-in fees**
Notary fees
Points: Limited to two. Based on (95% equity reinvestment)
Pool/Spa inspection
Recording fees
Roof inspection
Septic report (only if required by lender)
Statement fees
Tax service (Limited)
Tax stamps
Termite inspection
Title insurance
Transfer tax (city and/or county)

2.NON-REIMBURSABLE ITEMS

Any items not specifically covered by policy or negotiated between buyer and seller
Application fee
Bonds
Buy downs
Construction Loans*
Fix-up expenses, repairs, maintenance costs
Homeowner Association dues/Association Transfer fees
Impound accounts
Insurance
Interest
Late charges

2.NON-REIMBURSABLE ITEMS - continued

Mortgage insurance
Photos
Principal
Processing Fee
Repairs
Soil report
Taxes
Underwriting fees

*Consult with Relocation Services for customary items in the county of the purchase.

**Consult Relocation Services for current guidelines.

all information is subject to change. If there are any
ase call Relocation Services at (415) 817-8294.

APPOINTMENT LOG

The log is designed to assist you schedule and monitor the individuals required to visit your home.

Please notify your Consultant IMMEDIATELY if an individual fails to keep an appointment.

	NAME	DATE	TIME
Appraiser	1. _____	_____	_____
	2. _____	_____	_____
	3. _____	_____	_____
Broker	1. _____	_____	_____
	2. _____	_____	_____
Termite Inspector			
Pool/Spa Inspector			
Septic Inspector			
*Roof Inspector			
**Assigned REALTOR			

*May be required due to age or condition
**Final walk through required for Appraised Value Sale only

QUESTIONS/ANSWERS

Appraised Value Offer

Q: *What type of input do I have in determining the Appraised Value Offer of my home?*

A: You may participate in the appraisal process. To do this, complete the Appraisal Worksheet form and provide a copy to each appraiser at the time of the appraisal and a copy to the home purchase firm.

Q: *If I accept the Appraised Value Offer, when am I no longer responsible for the mortgage payments, etc., on my home?*

A: The Date of Possession of your home will be either (1) the date you vacate your home, or (2) the date your Contract is received by the home purchase firm, **whichever is later**. As of the Date of Possession, you are no longer financially responsible for your home, provided no repairs/inspections, etc., remain uncompleted.

Inspections

Q: *What inspections are necessary?*

A: A termite/wood-destroying pest and organism inspection is required. Where applicable, a well and/or septic inspection; swimming pool and/or spa/hot tub, radon gas inspection. If any report is unclear or incomplete, the home purchase firm will order a second inspection. Other inspections may be required depending on property conditions. All inspections will be paid for by PG&E.

Q: *What is a "home inspection"?*

A: Home inspections are required. This is a general inspection of the structure of the house, plumbing, heating, electrical, air conditioning, solar, all appliances, and roof to determine if everything is in good working order and meets code requirements. The inspection is done by a home inspector, if available, otherwise a general contractor is used. These are ordered by the home purchase firm and paid for by PG&E.

Q: *What happens if an inspection, etc., indicates that repairs are required?*

A: You must have the work completed, have a reinspection done, and submit the clear report to the home purchase firm prior to receiving your final equity.

Q: *If an inspection, etc., indicates repairs are required and (1) I want to move to my new home prior to the completion of the necessary repairs on my existing home, or (2) I just don't want the bother of obtaining bids and ensuring the work is complete, etc., what are my options?*

A: The home purchase firm will obtain an estimate for the required work and withhold two times this amount (termite work excepted) from your equity. By withholding additional dollars, it will not be necessary to request additional funds from you should the estimate be low. Once the work is completed, the home purchase firm will refund any excess dollars to you immediately.

Q: *At the same time I selected appraisers, the home purchase firm informed me that one or two Brokers' Market Analysis would also be ordered. What does this mean? Will the Brokers' Market Analysis affect the appraiser's value?*

A: The opinion(s) provide the home purchase firm with marketing strategies should you turn the home over to them. At the same time, the Brokers may make recommendations on how to make the property more marketable. This information will also be given to you to help you sell the home during your 60-day marketing period. The appraisers' final value is independent of the Brokers' Opinions.

Q: *What should I do when I receive an offer to purchase my home?*

A: Call your Consultant immediately. If your Consultant is not available, include the clause "Subject to review by the home purchase firm" in your acceptance.

Amended Value Offer

Q: *If I am able to find a buyer willing to purchase my home for more than the Appraised Value offer or even at the Appraised Value offer, is it beneficial to me to assign the offer to the home purchase firm for closing?*

A: Yes. The home purchase firm will: (1) handle all the details; (2) advance either 98 percent of your equity based on the **Appraised Value offer** or the amount required to purchase the new home, whichever is **less**.

Should the assigned offer fail to close, the Appraised Value offer will be amended to reflect the sales price.

Q: *If I assign an offer, will my Realtor receive a commission?*

A: Yes. This cost is paid by the home purchase firm at the close of escrow and assumed by PG&E.

Q: *Why must a purchase contract be signed only by the Home Purchase Firm?*

A: In order to meet Internal Revenue Service guidelines, the purchase and sale agreement can be signed **only** by your buyer(s) and the Home Purchase Firm. The Power of Attorney you sign allows the Home Purchase Firm to sign in your behalf as your nominee. Failure to follow these guidelines will negate the benefit of using the Home Purchase Firm AND will result in a substantial tax liability for you.

Equity Advances

Q: *What if I want two advances of my equity: one to be forwarded to the title company handling the closing of my new home and one to be given directly to me so that I may begin redecorating the new home, etc.?*

A: Advances are made only to escrow accounts. The equity advance to escrow is a benefit provided so that you will not be subject to the customary closing procedures (no funds received from the existing home until close of escrow). With the advance, you are able to purchase your new home in an expeditious manner.

CAL VET/VA Loan Transfer

Q: *What if I have a CAL VET or VA loan on my present home that I want to transfer to my new home, but I am unable to make the transfer for six to eight months due to the state/federal procedures?*

A: The home purchase firm will take your home into inventory while you continue to make mortgage payments; however, if the home purchase firm is able to find a buyer prior to the transfer of your CAL VET/VA loan, you would be required to pay off the loan so that there is clear title. (Notify the home purchase firm immediately if you plan to transfer your loan.)

GLOSSARY OF TERMS

Amended Value

A negotiated offer, presented by a Broker, which the homeowner and home purchase firm determine exceeds or equals the Appraised Value offer and which the homeowner, upon acceptance, instructs the home purchase firm to close and administer. Should this sale fail to close, the Appraised Value Offer will be amended to reflect the sales price of the offer, which was assigned.

Appraisal Worksheet

A form to be completed by each new hire, with the assistance of a Broker, supplying pertinent comparable sales and listing data to the appraisers and home purchase firm.

Appraised Value Offer

The value derived from an average of two independently obtained appraisals and extended by the home purchase firm to a homeowner. The offer is valid for 60 days.

Contract for Sale

The document by which a new hire sells his/her home, or assigns his/her home for sale to the home purchase firm.

Date of Possession (Appraised Value Sale)

The date the homeowner vacates the home provided the home purchase firm has received signed contracts.

Equity Advances

Depending on individual need, two types are available:

- 1) A reasonable sum for an earnest money deposit on a residence in the new location.
- 2) The lesser of the amount required to purchase the new residence or 98 percent of equity based on the Appraised Value offer.

Exclusion Clause

Language commonly included in relocation-related listings, which allows a homeowner to sell his/her home to the home purchase firm for the Appraised Value offer without incurring the cost of a Broker's commission.

Independent Appraisers

Specially trained and certified professionals hired by the home purchase firm on a fee basis, who establishes the Appraised Value for residential real estate. Each appraiser used is experienced in establishing values in the area where a new hire's home is located.

Marketing Period

The period of 60 days, beginning with the postmark date of the written Appraised Value offer, during which a homeowner may choose to assign an independent sale or accept the Appraised Value Offer.

Proration Date

The date the home purchase firm assumes responsibility for the ongoing expenses (mortgage, insurance, utilities, etc.) of a property.

Vacate Period (Appraised Value Sale)

The period of time from the date of acceptance of the Appraised Value offer to the date the property is formally vacated (up to 60 days).

TAX SUMMARY FOR NEW HIRE HOMEOWNER – OFFICER
(moves **more** than 50 miles)

ASSISTANCE	TAXES WITHHELD	TAXES PAID BY
Household Move	None	Fully Excludable
Household Storage First 30 days	None	Fully Excludable
Over 30 days	Federal, State, FICA & SDI	Company: Flat Rate Employee: FICA (OASDI) & SDI
Moving Allowance	Federal, State, FICA & SDI	Employee*
Home Sale-Direct Reimbursement (In lieu of Home Purchase Firm)	Federal, State, FICA & SDI	Employee*
Tax Offset (up to one month's salary)**		
Home Purchase-Direct Reimbursement* AND Company Mortgage Program	Federal, State, FICA & SDI	Company: Flat rate up to maximum, excluding points. Employee: Points. Federal, State, FICA & SDI
Mortgage Interest Differential Allowance	Federal, State, FICA & SDI	Employee

*Taxes owed by the employee are deducted DIRECTLY from the reimbursement. This is an IRS requirement.

**Capped at \$10,000. Pro-rated based on reimbursement.

All reimbursements for moving expenses will be included on the employee's W-2 as other income except household move, storage (first 30 days).

Federal, State and FICA taxes withheld will also be included on the employee's W-2 whether paid by the employee or the company.

The company will furnish a Relocation Expense Summary, which is to be filed with the employee's tax return. The information will be provided by January 31, for the prior year's expenses.

The company uses a standard withholding rate 25% Federal, State*, 1.45% Medicare.

2009 FICA Limits:		6.20% (OASDI)	to	\$106,800
		1.45% (Medicare)	to	unlimited
2009 SDI	1.10%	to		\$90,669

*** State Tax, where appropriate, will be part of the Company tax gross-up.**

NOTE: **If an item is considered taxable, but paid directly to a vendor, any tax due will be deducted from the next payroll check.**

HOME PURCHASE-DIRECT REIMBURSEMENT

is intended only to illustrate process. The pay rates may not reflect actual rates in effect at the time of payment.

le Items:

Reimbursable Items:		Purchase Price :	\$225,000.00
Points	\$3,600.00		
Credit Report	50.00		
Document Preparation	150.00	2.5% of Purchase Price =	\$5,625.00
Appraisal	300.00	Home Inspection	+ 425.00
General Home Inspection	325.00	Total Reimbursed	\$6,050.00
Escrow Fees	450.00	Points -Employee Tax Liability	- 3600.00
Title Insurance	985.00		
Termite Inspection	95.00		
Notary Fees	25.00	Relocation Tax Liability	\$2,450.00
Recording Fees	35.00		
Tax Service	76.00		
Flood Check Fee	20.00		
Home Inspection	425.00	(Not Subject to the 2.5%cap)	
TOTAL	\$6,536.00		

f Tax Gross/Up & Withholding

if \$5,625 + \$425 = \$6,050 is reimbursed because it is the Lesser of actual or 2.5% of the purchase price. Points may be deductible as an itemized deduction so they'd up.

Total Amount Reimbursed:	\$6,050.00	Amount Company Paid Tax On:	\$2,450.00
Gross Up:(FIT, SIT & Medicare)	1,363.23	Co. Paid Gross Up: (FIT, SIT & Medicare)	1,363.23
		Amount Employee Pays Tax On:	3,600.00
Amount Reported:	<u>\$7,413.23</u>	Amount Reported:	<u>\$7,413.23</u>
	<u>Total Taxes</u>	<u>Tax Paid by PG&E</u>	<u>Employee Tax Liability</u>
Amount Taxes were based on:		\$2,450.00	"Points" \$3,600.00
FIT*	25.00% \$1,853.31	\$953.31	\$900.00
SIT*	9.3% 570.63	354.63	216.00
Medicare*	1.45% 107.49	55.29	52.20
OASDI	6.20% 459.62		459.62
SDI	1.10% 81.55		59.31
*TOTAL	64.25% <u>\$3,072.60</u>	<u>\$1,363.23</u>	<u>\$1,709.37</u>
AMOUNT TO BE WITHHELD:		<u>1,709.37</u>	
oyee: \$4,340.63	(\$7,413.23 – 1,363.23 - 1,709.37)`		

[PACIFIC GAS AND ELECTRIC COMPANY LETTERHEAD]
AMENDMENT TO POSTRETIREMENT LIFE INSURANCE PLAN OF
THE PACIFIC GAS AND ELECTRIC COMPANY

The Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (the "Plan") is hereby amended as described below.

1. On or prior to December 31, 2008, certain participants in the Plan identified by the Pacific Gas and Electric Company ("PG&E"), in its sole discretion, shall be given an election to receive a cash payment or a life insurance benefit under the Plan on such terms determined by PG&E in its sole discretion, such that on and after January 1, 2009 only life insurance will be provided under the Plan and no person may make an election to receive cash, a life insurance benefit, or any combination thereof under the Plan.
2. All cash payments under the Plan shall be made no later than the 15th day of the third month following the later of the end of the calendar year or PG&E Corporation's taxable year in which the applicable Plan participant separates from service (within the meaning of Section 409A of the Internal Revenue Code of 1986).
3. All life insurance benefit proceeds under the Plan shall be paid in a single lump sum to the Plan participant's beneficiary at the time of such Participant's death.
4. Each payment and benefit under the Plan shall be treated as a "separate payment" for purposes of Section 409A.
5. Notwithstanding anything to the contrary set forth in the Plan, to the extent (i) any compensation or benefits to which a participant becomes entitled under the Plan, or any agreement or plan referenced therein, in connection with the participant's "separation from service" (within the meaning of Section 409A) constitute deferred compensation subject to (and not exempt from) Section 409A and (ii) the participant is deemed at the time of such separation to be a "specified employee" under Section 409A, then such compensation or benefits shall not be made or commence until the earlier of (i) six (6)-months after such separation or (ii) the date of the participant's death following such separation; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the participant under Section 409A(a)(1) in the absence of such delay. Upon the expiration of the applicable delay period, any compensation or benefits which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the participant or the participant's beneficiary in one lump sum on the first business day immediately following the end of such delay period.

6. The following sentence is added at the end of Section 1.12 of the Plan: “Additionally, for purposes of this Plan, Service shall include service with PG&E Corporation and its affiliates.”

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President - Human Resources

Date: December 30, 2008

Director Compensation

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION**

September 17, 2008

BE IT RESOLVED that, effective January 1, 2009, advisory directors and directors who are not employees of this corporation or Pacific Gas and Electric Company (collectively, "non-employee directors") shall be paid a retainer of \$13,750 per calendar quarter, which shall be in addition to fees paid for attendance at Board meetings, Board committee meetings, and shareholder meetings; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the non-employee director who serves as lead director shall be paid an additional retainer of \$12,500 per calendar quarter; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the non-employee director who is duly appointed to chair the Audit Committee of this Board shall be paid an additional retainer of \$12,500 per calendar quarter, and the non-employee directors who are duly appointed to chair the other permanent committees of this Board shall be paid an additional retainer of \$1,875 per calendar quarter; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, non-employee directors shall be paid a fee of \$1,750 for each meeting of the Board and each meeting of a Board committee attended; provided, however, that non-employee directors who are members of the Audit Committee shall be paid a fee of \$2,750 for each meeting of the Audit Committee attended; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, non-employee directors attending any meeting of this corporation's shareholders that is not held on the same day as a meeting of this Board shall be paid a fee of \$1,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that, subject to compliance with applicable securities laws, any non-employee director may participate in a Directors' Voluntary Stock Purchase Program by instructing the Corporate Secretary to withhold an amount equal to but not less than 20 percent of his or her meeting fees and/or quarterly retainers for the purpose of acquiring shares of this corporation's common stock on behalf of said director; provided, however, that once a non-employee director has so instructed the Corporate Secretary, said director may not modify or discontinue such instruction for at least 12 calendar months; and

BE IT FURTHER RESOLVED that non-employee directors shall be eligible to participate in the PG&E Corporation 2006 Long-Term Incentive Plan under the terms and conditions of that Plan, as adopted by this Board and as may be amended from time to time; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in connection with attending Board, Board committee, or shareholder meetings, or participating in other activities undertaken on behalf of this corporation; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the resolution on this subject adopted by the Board of Directors on February 20, 2008 is hereby superseded.

Director Compensation**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY**

September 17, 2008

BE IT RESOLVED that, effective January 1, 2009, advisory directors and directors who are not employees of this company or PG&E Corporation (collectively, "non-employee directors") shall be paid a retainer of \$13,750 per calendar quarter, which shall be in addition to any fees paid for attendance at Board meetings, Board committee meetings, and shareholder meetings; provided, however, that a non-employee director shall not be paid a retainer by this company for any calendar quarter during which such director also serves as a non-employee director of PG&E Corporation; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the non-employee director who serves as lead director shall be paid an additional retainer of \$12,500 per calendar quarter; provided, however, that a non-employee director who serves as lead director shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as lead director of the PG&E Corporation Board of Directors; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the non-employee director who is duly appointed to chair the Audit Committee of this Board shall be paid an additional retainer of \$12,500 per calendar quarter, and the non-employee directors who are duly appointed to chair the other permanent committees of this Board shall be paid an additional retainer of \$1,875 per calendar quarter; provided, however, that a non-employee director duly appointed to chair a permanent committee of this Board shall not be paid an additional retainer by this company for any calendar quarter during which such director also serves as chair of the corresponding committee of the PG&E Corporation Board of Directors; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, non-employee directors attending any meeting of the Board that is not held concurrently or sequentially with a meeting of the Board of Directors of PG&E Corporation, or any meeting of a Board committee that is not held concurrently or sequentially with a meeting of the corresponding committee of

the PG&E Corporation Board, shall be paid a fee of \$1,750 for each such Board or Board committee meeting attended; provided, however, that non-employee directors attending any meeting of the Audit Committee of this Board that is not held concurrently or sequentially with a meeting of the Audit Committee of the PG&E Corporation Board shall be paid a fee of \$2,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, non-employee directors attending any meeting of this company's shareholders that (1) is not held on the same day as a meeting of this Board or a meeting of the Board of Directors of PG&E Corporation, and (2) is not held concurrently or sequentially with a meeting of the shareholders of PG&E Corporation shall be paid a fee of \$1,750 for each such meeting attended; and

BE IT FURTHER RESOLVED that, subject to compliance with applicable securities laws, any non-employee director may participate in a Directors' Voluntary Stock Purchase Program by instructing the Corporate Secretary to withhold an amount equal to but not less than 20 percent of his or her meeting fees and/or quarterly retainers for the purpose of acquiring shares of PG&E Corporation common stock on behalf of said director; provided, however, that once a non-employee director has so instructed the Corporate Secretary, said director may not modify or discontinue such instruction for at least 12 calendar months; and

BE IT FURTHER RESOLVED that members of this Board shall be reimbursed for reasonable expenses incurred in connection with attending Board, Board committee, or shareholder meetings, or participating in other activities undertaken on behalf of this company; and

BE IT FURTHER RESOLVED that, effective January 1, 2009, the resolution on this subject adopted by the Board of Directors on February 20, 2008 is hereby superseded.

PG&E Corporation
2006 Long-Term Incentive Plan

PLAN HISTORY AND NOTES TO COMPANY

December 15, 2004	Board adopts Plan with a reserve of 12 million shares.
April 20, 2005	Shareholders approve Plan.
January 1, 2006	Plan Effective Date
February 15, 2006	Change in control provisions are amended
December 20, 2006	Board amends Section 7 containing the terms for automatic awards for Non-Employee Directors, effective January 1, 2007
October 17, 2007	Board amends Section 7 as follows: Define “Grant Date” for a particular calendar year as the first business day in March of that calendar year. Previously, the grant date for awards in 2006 and 2007 was the first business day in January of that particular calendar year. This amendment becomes effective starting with grants for 2008. Amend the basis for calculating the per share value of stock option awards, so it is based on the average closing price of Stock during the months of November, December, and January preceding the grant. Previously, the per share value of stock options awards for grants in 2006 and 2007 was based on the average closing price of Stock during the preceding month of November. This amendment becomes effective starting with grants for 2008. Clarify the language for settling restricted stock awards upon a Nonemployee Director’s retirement from the Board, to indicate that shares credited to a Nonemployee Director’s Restricted Stock Unit account may be settled after a Nonemployee Director ceases to be a member of the Board of Directors following five years of service on the Board.
September 17, 2008	Board amends Section 7 containing the terms for automatic awards for Nonemployee Directors, effective January 1, 2009, to increase the total value of annual equity awards to Nonemployee Directors from \$80,000 to \$90,000. Of this amount, \$45,000 of equity awards shall be Restricted Stock, and the remaining \$45,000 shall be a mixture of Options and Restricted Stock Units, consistent with the Plan and with each Nonemployee Director’s election.
Effective January 1, 2009	Plan is amended to comply with the final regulations under Section 409A of the Code

February 18, 2009

Plan is amended to delay grant and pricing of 2009 grants for non-employee directors, to be consistent with 2009 grants to employees.

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PG&E Corporation

2006 Long-Term Incentive Plan

(As adopted effective January 1, 2006, and

as amended effective on February 15, 2006, December 20, 2006, October 17, 2007, September 17, 2008, January 1, 2009, and February 18, 2009)

1. ESTABLISHMENT, PURPOSE AND TERM OF PLAN.

1.1 **Establishment.** The PG&E Corporation 2006 Long-Term Incentive Plan (the “**Plan**”) is hereby established effective as of January 1, 2006 (the “**Effective Date**”), provided it has been approved by the shareholders of the Company.

1.2 **Purpose.** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company’s shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which all of the shares of Stock available for issuance under the Plan have been issued and all restrictions on such shares under the terms of the Plan and the agreements evidencing Awards granted under the Plan have lapsed. However, all Awards shall be granted, if at all, within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than ten (10) years from the date of shareholder approval of the Plan.

2. DEFINITIONS AND CONSTRUCTION.

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) “**Affiliate**” means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term “control” (including the term “controlled by”) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) “**Award**” means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) “**Award Agreement**” means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant.

(d) “**Board**” means the Board of Directors of the Company.

(e) “**Change in Control**” means, unless otherwise defined by the Participant’s Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any “person” (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person’s capacity as such fiduciary), directly or indirectly, becomes the “beneficial owner” (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing twenty percent (20%) or more of the combined voting power of the Company’s then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office who were Directors at the beginning of the period; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the voting stock of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting stock of the surviving entity or any parent of such surviving entity) at least seventy percent (70%) of the Combined Voting Power of the Company, such surviving entity or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

(iv) the approval of the Shareholders of the Company of any (1) sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Company, or (2) any plan or proposal for the liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term “**Combined Voting Power**” shall mean the combined voting power of the Company’s or other relevant entity’s then outstanding voting stock.

(f) “**Code**” means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) “**Committee**” means the Compensation Committee or other committee of the Board duly appointed to administer the Plan and having such powers as shall be specified by

the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) “**Company**” means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) “**Consultant**” means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) “**Deferred Compensation Award**” means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) “**Director**” means a member of the Board.

(l) “**Disability**” means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code, except as otherwise set forth in the Plan or an Award Agreement.

(m) “**Dividend Equivalent**” means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) “**Employee**” means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director’s fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual’s employment or termination of employment, as the case may be. For purposes of an individual’s rights, if any, under the Plan as of the time of the Company’s determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) “**Exchange Act**” means the Securities Exchange Act of 1934, as amended.

(p) “**Fair Market Value**” means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) “**Incentive Stock Option**” means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) “**Insider**” means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) “**Mandatory Retirement**” means retirement as a Director at age 70 or at such other age as may be specified in the retirement policy for the Board in effect at the time of a Nonemployee Director’s termination of Service as a Director.

(t) “**Net-Exercise**” means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

$X = Y(A-B)/A$, where

X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;

Y = the total number of shares with respect to which the Participant has elected to exercise the Option;

A = the Fair Market Value of one (1) share of Stock;

B = the exercise price per share (as defined in the Participant’s Award Agreement).

- (u) “ **Nonemployee Director** ” means a Director who is not an Employee.
- (v) “ **Nonemployee Director Award** ” means an Award granted to a Nonemployee Director pursuant to Section 7 of the Plan.
- (w) “ **Nonstatutory Stock Option** ” means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.
- (x) “ **Officer** ” means any person designated by the Board as an officer of the Company.
- (y) “ **Option** ” means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.
- (z) “ **Option Expiration Date** ” means the date of expiration of the Option’s term as set forth in the Award Agreement.
- (aa) “ **Parent Corporation** ” means any present or future “parent corporation” of the Company, as defined in Section 424(e) of the Code.
- (bb) “ **Participant** ” means any eligible person who has been granted one or more Awards.
- (cc) “ **Participating Company** ” means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.
- (dd) “ **Participating Company Group** ” means, at any point in time, all entities collectively which are then Participating Companies.
- (ee) “ **Performance Award** ” means an Award of Performance Shares or Performance Units.
- (ff) “ **Performance Award Formula** ” means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more threshold levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.
- (gg) “ **Performance Goal** ” means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.
- (hh) “ **Performance Period** ” means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(ii) “ **Performance Share** ” means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(jj) “ **Performance Unit** ” means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(kk) “ **Restricted Stock Award** ” means an Award of Restricted Stock.

(ll) “ **Restricted Stock Unit** ” or “ **Stock Unit** ” means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12, as applicable, and the Participant’s Award Agreement.

(mm) “ **Restriction Period** ” means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(nn) “ **Retirement** ” means termination as an Employee of a Participating Company at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(oo) “ **Rule 16b-3** ” means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(pp) “ **SAR** ” or “ **Stock Appreciation Right** ” means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(qq) “ **Section 162(m)** ” means Section 162(m) of the Code.

(rr) “ **Section 409A Change in Control** ” means a “change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation,” within the meaning of Section 409A of the Code, as such definition applies to the Company.

(ss) “ **Securities Act** ” means the Securities Act of 1933, as amended.

(tt) “ **Separation from Service** ” means a Participant’s “separation from service,” within the meaning of Section 409A of the Internal Revenue Code.

(uu) “ **Service** ” means a Participant’s employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant’s Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the

Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the one hundred eighty-first (181st) day following the commencement of such leave any Incentive Stock Option held by the Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option, unless the Participant's right to return to Service with the Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(vv) " **Stock** " means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(ww) " **Stock-Based Awards** " means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(xx) " **Subsidiary Corporation** " means any present or future "subsidiary corporation" of the Company, as defined in Section 424(f) of the Code.

(yy) " **Ten Percent Owner** " means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(zz) " **Vesting Conditions** " mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. **ADMINISTRATION .**

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by

the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee and provided further that at the time of making such Awards the Chief Executive Officer also is a Director.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a “publicly held corporation” within the meaning of Section 162(m), the Board may establish a Committee of “outside directors” within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules and Awards to Nonemployee Directors shall be granted automatically pursuant to Section 7 of the Plan);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the

Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained, (vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

- (e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;
- (f) to approve one or more forms of Award Agreement;
- (g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto;
- (h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;
- (i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee;
- (j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;
- (k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and
- (l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing.** Without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Board shall not approve a program providing for either (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price or (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof. This paragraph shall not be construed to apply to

“issuing or assuming a stock option in a transaction to which section 424(a) applies,” within the meaning of Section 424 of the Code.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys’ fees, actually and necessarily incurred in connection with the defense of any action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **SHARES SUBJECT TO PLAN.**

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2 and subject to Section 409A of the Code, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be twelve million (12,000,000) and shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan. Shares of Stock shall not be deemed to have been issued pursuant to the Plan (a) with respect to any portion of an Award that is settled in cash or (b) to the extent such shares are withheld or reacquired by the Company in satisfaction of tax withholding obligations pursuant to Section 16.2. Upon payment in shares of Stock pursuant to the exercise of an SAR, the number of shares available for issuance under the Plan shall be reduced only by the number of shares actually issued in such payment. If the exercise price of an Option is paid by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant, or by means of a Net-Exercise, the number of shares available for issuance under the Plan shall be reduced only by the net number of shares for which the Option is exercised.

4.2 **Adjustments for Changes in Capital Structure.** Subject to any required action by the shareholders of the Company, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the

shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4, in the Nonemployee Director Awards to be granted automatically pursuant to Section 7, and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

5. **ELIGIBILITY AND AWARD LIMITATIONS.**

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors. For purposes of the foregoing sentence, "Employees," "Consultants" and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Nonemployee Director Award may be granted only to a person who, at the time of grant, is a Nonemployee Director.

5.2 **Participation.** Awards other than Nonemployee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However, excepting Nonemployee Director Awards, eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) **Persons Eligible.** An Incentive Stock Option may be granted only to a person who, on the effective date of grant, is an Employee of the Company, a Parent Corporation or a Subsidiary Corporation (each being an "**ISO-Qualifying Corporation**"). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1.

(b) **Fair Market Value Limitation.** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any

calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars (\$100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 Award Limits.

(a) **Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed twelve million (12,000,000) shares. The maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to all Awards other than Incentive Stock Options shall be the number of shares determined in accordance with Section 4.1, subject to adjustment as provided in Section 4.2 and further subject to the limitation set forth in Section 5.4(b) below.

(b) **Aggregate Limit on Full Value Awards.** Subject to adjustment as provided in Section 4.2, in no event shall more than twelve million (12,000,000) shares in the aggregate be issued under the Plan pursuant to the exercise or settlement of Restricted Stock Awards, Restricted Stock Unit Awards and Performance Awards ("Full Value Awards"). Except with respect to a maximum of five percent (5%) of the shares of Stock authorized in this Section 5.4(b), any Full Value Awards which vest on the basis of the Participant's continued Service shall not provide for vesting which is any more rapid than annual pro rata vesting over a three (3) year period and any Full Value Awards which vest upon the attainment of Performance Goals shall provide for a Performance Period of at least twelve (12) months.

(c) **Section 162(m) Award Limits.** The following limits shall apply to the grant of any Award if, at the time of grant, the Company is a "publicly held corporation" within the meaning of Section 162(m).

(i) **Options and SARs.** Subject to adjustment as provided in Section 4.2, no Employee shall be granted within any fiscal year of the Company one or more Options or Freestanding SARs which in the aggregate are for more than 400,000 shares of Stock reserved for issuance under the Plan.

(ii) **Restricted Stock and Restricted Stock Unit Awards.** Subject to adjustment as provided in Section 4.2, no Employee shall be granted within any fiscal year of the Company one or more Restricted Stock Awards or Restricted Stock Unit Awards, subject to

Vesting Conditions based on the attainment of Performance Goals, for more than 400,000 shares of Stock reserved for issuance under the Plan.

(iii) **Performance Awards.** Subject to adjustment as provided in Section 4.2, no Employee shall be granted (1) Performance Shares which could result in such Employee receiving more than 400,000 shares of Stock reserved for issuance under the Plan for each full fiscal year of the Company contained in the Performance Period for such Award, or (2) Performance Units which could result in such Employee receiving more than two million dollars (\$2 million) for each full fiscal year of the Company contained in the Performance Period for such Award. No Participant may be granted more than one Performance Award for the same Performance Period.

6. **TERMS AND CONDITIONS OF OPTIONS.**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and, except as otherwise set forth in Section 7 with respect to Nonemployee Director Options, shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price.** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted pursuant to an assumption or substitution for another option in a manner qualifying under the provisions of Section 424(a) of the Code.

6.2 **Exercisability and Term of Options.** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) **Forms of Consideration Authorized.** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a “**Cashless Exercise**”), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration.

(b) **Limitations on Forms of Consideration.**

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company’s stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company’s sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) **Option Exercisability .** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant’s termination of Service only during the applicable time periods provided in the Award Agreement.

(b) **Extension if Exercise Prevented by Law .** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 14.1 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the Option Expiration Date.

(c) **Extension if Participant Subject to Section 16(b) .** Notwithstanding the foregoing, if a sale within the applicable time periods of shares acquired upon the exercise of the

Option would subject the Participant to suit under Section 16(b) of the Exchange Act, the Option shall remain exercisable until the earliest to occur of (i) the tenth (10th) day following the date on which a sale of such shares by the Participant would no longer be subject to such suit, (ii) the one hundred and ninetieth (190th) day after the Participant's termination of Service, or (iii) the Option Expiration Date.

6.5 **Transferability of Options.** During the lifetime of the Participant, an Option shall be exercisable only by the Participant or the Participant's guardian or legal representative. Prior to the issuance of shares of Stock upon the exercise of an Option, the Option shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the Award Agreement evidencing such Option, a Nonstatutory Stock Option shall be assignable or transferable subject to the applicable limitations, if any, described in the General Instructions to Form S-8 Registration Statement under the Securities Act.

7. **TERMS AND CONDITIONS OF NONEMPLOYEE DIRECTOR AWARDS.**

Nonemployee Director Awards shall be evidenced by Award Agreements in such form as the Board shall from time to time establish. Such Award Agreements may incorporate all or any of the terms of the Plan by reference, shall be automatic and non-discretionary and shall comply with and be subject to the terms and conditions set forth in this Section 7.

For purposes of this Section 7, Nonemployee Director awards for any given calendar year shall be granted on the first business day of March in that calendar year, except that awards made in the year 2009 shall be granted on March 9, 2009 (the "Grant Date").

7.1 **Automatic Grant of Restricted Stock.**

(a) **Timing and Amount of Grant.** For each calendar year, each person who is a Nonemployee Director on the Grant Date shall be granted a Restricted Stock Award to purchase a number of shares of Stock determined by dividing forty-five thousand dollars (\$45,000) by the Fair Market Value of the Stock on the Grant Date, and rounding down to the nearest whole number, except that for awards granted in 2009 the number of shares shall be determined by dividing \$45,000 by the average Fair Market Value of the Stock for the first five trading days of March 2009.

(b) **Vesting.** The shares subject to the Restricted Stock Award granted pursuant to Section 7.1(a) shall vest in equal annual installments of twenty percent (20%) on each anniversary of the Grant Date, with one hundred percent (100%) of the shares vested on the fifth anniversary of the Grant Date.

7.2 **Annual Election to Receive Nonstatutory Stock Option and Restricted Stock Units.** On a date no later than December 31 of each calendar year during the term of the Plan, each person who is then a Nonemployee Director shall deliver to the Board a written election to receive either Nonstatutory Stock Options or Restricted Stock Units, or both, with an aggregate value of \$45,000, on the Grant Date for the following calendar year, provided the person

continues to be a Nonemployee Director on the Grant Date. A Nonemployee Director may allocate between Nonstatutory Stock Options and Restricted Stock Units in minimum increments with a value equal to \$5,000, as determined in accordance with Sections 7.3 and 7.4. All awards of Nonstatutory Stock Options and Restricted Stock Units made to Nonemployee Directors shall comply with the provisions of Sections 7.3 and 7.4, respectively. A Nonemployee Director who fails to make a timely election or who first becomes a Nonemployee Director after December 31 but before the Grant Date for the following calendar year shall be awarded Nonstatutory Stock Options and Restricted Stock Units each with a value of \$22,500, as determined in accordance with Sections 7.3 and 7.4, provided the Nonemployee Director continues to be a Nonemployee Director on the Grant Date.

7.3 Grant of Nonstatutory Stock Option.

(a) **Timing and Amount of Grant** . For each calendar year, unless a Nonemployee Director made an election to decline the award of a Nonstatutory Stock Option in accordance with Section 7.7, each person who is a Nonemployee Director on the Grant Date shall receive a grant of a Nonstatutory Stock Option with an aggregate value equal to \$5,000, \$10,000, \$15,000, \$20,000, \$25,000 \$30,000, \$35,000, \$40,000, or \$45,000 as previously elected by the Nonemployee Director (or \$22,500 in the case of a Nonemployee Director who failed to make a timely election or who became a Nonemployee Director before the Grant Date for a particular year but after December 31 of the previous year) (the **"Elected Option Value"**).

The number of shares subject to the Nonstatutory Stock Option shall be determined by dividing the Elected Option Value by the value of a Nonstatutory Stock Option to purchase a single share of Stock as of the Grant Date. The per share option value shall be calculated in accordance with the Black-Scholes stock option valuation method using the average closing price of Stock during the preceding months of November, December, and January, and reducing the per option value by twenty percent (20%). The resulting number of shares subject to the Nonstatutory Stock Option shall be rounded down to the nearest whole share. No person shall receive more than one grant of Nonstatutory Stock Options pursuant to this Section 7.3(a) during any calendar year.

(b) **Exercise Price and Payment** . The exercise price of each Nonstatutory Stock Option granted pursuant to Section 7.3(a) shall be the Fair Market Value of the Stock on the Grant Date. The payment of the exercise price for the number of shares of Stock being purchased pursuant to the Nonstatutory Stock Option shall be made in accordance with the provisions of Section 6.3.

(c) **Vesting and Exercisability** . The Nonstatutory Stock Option granted in accordance with this Section shall become vested and exercisable as to one third (1/3) of the shares subject to the Nonstatutory Stock Option on the second, third and fourth anniversaries of the Grant Date, respectively. The Nonstatutory Stock Option shall terminate ten (10) years after the Grant Date, unless earlier terminated in accordance with its provisions.

7.4 Grant of Restricted Stock Unit.

(a) **Timing and Amount of Grant** . For each calendar year, unless a Nonemployee Director made an election to decline the award of a Restricted Stock Unit in

accordance with Section 7.7, on the Grant Date each person who is a Nonemployee Director on the Grant Date shall receive a grant of a Restricted Stock Unit Award with an aggregate value (as determined by the Fair Market Value of the Stock on the Grant Date) equal to \$5,000, \$10,000, \$15,000, \$20,000, \$25,000, \$30,000, \$35,000, \$40,000, or \$45,000, as previously elected by the Nonemployee Director (or \$22,500 in the case of a Nonemployee Director who failed to make a timely election or who became a Nonemployee Director after December 31 but before the Grant Date) (the ***“Elected Stock Unit Value”***). The number of shares subject to the Restricted Stock Unit Award shall be determined by dividing the Elected Stock Unit Value by the Fair Market Value of the Stock as of the Grant Date (including fractions computed to three decimal places), except that for awards in 2009, the number of shares subject to the Restricted Stock Unit Awards shall be determined by dividing the Elected Stock Unit value by the average Fair Market Value of the Stock for the first five trading days of March 2009 (including fractions computed to three decimal places). The Restricted Stock Units awarded to a Nonemployee Director shall be credited to the director’s Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Nonemployee Director in accordance with this Section 7.4(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the Grant Date, and shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.4(a) during any calendar year.

(b) ***Dividend Rights***. Each Nonemployee Director’s Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Settlement of Restricted Stock Unit Award***. Settlement of the shares credited to a Nonemployee Director’s Restricted Stock Unit account shall be made as to all shares of Stock covered by the Restricted Stock Unit upon the earliest of (i) the Nonemployee Director’s Separation from Service due to Mandatory Retirement, (ii) the Nonemployee Director’s Separation from Service after five years of continuous service on the Board (“Director Retirement”), (iii) the Nonemployee Director’s death, (iv) the Nonemployee Directors Disability (within the meaning of Section 409A of the Code), (v) a Change in Control that also constitutes a Section 409A Change in Control and (vi) the Nonemployee Director’s Separation from Service following a Change in Control. Settlement shall be made only in the form of shares of Stock equal to the number of Restricted Stock Units credited to the Nonemployee Director’s account on the date of distribution, rounded down to the nearest whole share. In the event of a distribution pursuant to Section 7(c)(iii) or 7(c)(iv), the Nonemployee Director shall receive the Stock in a lump sum distribution at the time of the applicable distribution event. In the case of Sections 7(c)(i), 7(c)(ii), 7(c)(v) and 7(c)(vi), the Nonemployee Director shall receive the Stock in a lump sum distribution in January of the year following the year in which the applicable distribution event occurs; provided, however, that the Nonemployee Director may elect, no later than December 31 of the calendar year prior the date of grant of the Restricted Stock Unit (or such later time permitted by Section 409A), (1) to receive a series of ten or less approximately equal annual installments commencing no later than January of the year following the year in

which the applicable distribution event occurred (such election to apply to all such distribution events) or (2) to instead receive a lump sum at the time that the applicable distribution event occurs (such election to apply to all such distribution events).

7.5 Effect of Termination of Service as a Nonemployee Director.

(a) **Status of Award .** Subject to earlier termination of the Nonemployee Director Award as otherwise provided herein, the status of a Nonemployee Director Award shall be determined as follows:

(i) **Death or Disability.** If the Nonemployee Director's Service terminates due to death or Disability (1) all shares subject to the Restricted Stock Award shall become fully vested, and the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock by reason of the Participant's death) shall have the right to resell or transfer such shares at any time; and (2) all Nonstatutory Stock Options held by the Participant shall become fully vested and exercisable, and the Participant (or the Participant's legal representative or other person who acquired the rights to the Nonstatutory Stock Option by reason of the Participant's death) shall have the right to exercise the Nonstatutory Stock Options until the earlier of (a) the date that is twelve (12) months after the date on which the Participant's Service terminated, or (b) the Option Expiration Date. If the Nonemployee Director becomes "disabled," within the meaning of Section 409A of the Code or in the event of the Nonemployee Director's death, all Restricted Stock Units credited to the Nonemployee Director's account shall immediately vest and become payable, in accordance with Section 7(c), to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(ii) **Mandatory Retirement .** If the Participant's Service terminates because of the Mandatory Retirement of the Participant (1) all shares subject to the Restricted Stock Award shall become fully vested, and the Participant shall have the right to resell or transfer such shares at any time; and (2) all Nonstatutory Stock Options held by the Participant shall become fully vested and exercisable and the Participant shall have the right to exercise the Nonstatutory Stock Options until the earlier of (a) the date that is five (5) years after the date on which the Participant's Service terminated, or (b) the Option Expiration Date. If the Nonemployee Director Separates from Service due to Mandatory Retirement, all Restricted Stock Units credited to the Nonemployee Director's account shall immediately vest and become payable to the Participant in accordance with Section 7.4(c) above.

(iii) **Other Termination of Service.** If the Participant's Service terminates for any reason other than those enumerated in Sections 7.5(a)(i) and 7.5(a)(ii), (1) any unvested shares of Restricted Stock shall be forfeited to the Company and from and after the date of such termination, the Participant shall cease to be a shareholder with respect to such forfeited shares and shall have no dividend, voting or other rights with respect thereto and (2) the unvested portion of any Nonstatutory Stock Option shall terminate, and any portion of the Nonstatutory Stock Option exercisable by the Participant on the date on which the Participant's Service terminated may be exercised until the earlier of (a) the date that is three (3) months after the date

on which the Participant's Service terminated, or (b) the Option Expiration Date. If the Nonemployee Director Separates from Service prior to the occurrence of any of the distribution events set forth in Section 7.4(c), all Restricted Stock Units credited to the Participant's account shall be forfeited on the date of such Separation from Service; provided, however, that if the Nonemployee Director Separates from Service due to a pending Disability determination such forfeiture shall not occur until a finding that such Disability has not occurred.

(iv) Notwithstanding the provisions of Section 7.5(i) through 7.5(iii) above, the Board, in its sole discretion, may establish different terms and conditions pertaining to Nonemployee Director Awards.

(b) **Extension if Exercise Prevented by Law .** Notwithstanding the foregoing, if the exercise of a Nonstatutory Stock Option within the applicable time periods set forth in Section 7.5(a) is prevented by the provisions of Section 14.1 below, the Nonstatutory Stock Option shall remain exercisable until three (3) months after the date the Participant is notified by the Company that the Nonstatutory Stock Option is exercisable, but in any event no later than the Option Expiration Date.

(c) **Extension if Participant Subject to Section 16(b) .** Notwithstanding the foregoing, if a sale within the applicable time periods set forth in Section 7.5(a) of shares acquired upon the exercise of the Nonstatutory Stock Option would subject the Participant to suit under Section 16(b) of the Exchange Act, the Nonstatutory Stock Option shall remain exercisable until the earliest to occur of (i) the tenth (10th) day following the date on which a sale of such shares by the Participant would no longer be subject to such suit, (ii) the one hundred and ninetieth (190th) day after the Participant's termination of Service, or (iii) the Option Expiration Date.

7.6 **Effect of Change in Control on Nonemployee Director Awards.** Upon the occurrence of a Change in Control, (i) the vesting of all shares of Restricted Stock granted pursuant to Section 7.1(a) shall be accelerated so that all such shares become fully vested, (ii) the vesting of Nonstatutory Stock Options granted pursuant to Section 7.3(a) shall be accelerated and such Nonstatutory Stock Options shall remain fully exercisable until the Option Expiration Date, and (iii) all Restricted Stock Units shall immediately vest and be settled in accordance with Section 7.4(c).

7.7 **Right to Decline Nonemployee Director Awards.** Notwithstanding the foregoing, any person may elect not to receive a Nonemployee Director Award by delivering written notice of such election to the Board no later than the day prior to the date such Nonemployee Director Award would otherwise be granted. A person so declining a Nonemployee Director Award shall receive no payment or other consideration in lieu of such declined Nonemployee Director Award. A person who has declined a Nonemployee Director Award may revoke such election by delivering written notice of such revocation to the Board no later than the day prior to the date such Nonemployee Director Award would be granted.

8. **TERMS AND CONDITIONS OF STOCK APPRECIATION RIGHTS .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a “ **Tandem SAR** ”) or may be granted independently of any Option (a “ **Freestanding SAR** ”). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) **Tandem SARs.** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) **Freestanding SARs.** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

8.4 **Deemed Exercise of SARs.** If, on the date on which an SAR would otherwise terminate or expire, the SAR by its terms remains exercisable immediately prior to such termination or expiration and, if so exercised, would result in a payment to the holder of such SAR, then any portion of such SAR which has not previously been exercised shall automatically be deemed to be exercised as of such date with respect to such portion.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant’s termination of Service only as provided in the Award Agreement.

8.6 **Nontransferability of SARs.** During the lifetime of the Participant, an SAR shall be exercisable only by the Participant or the Participant’s guardian or legal representative. Prior to the exercise of an SAR, the SAR shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the

Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution.

9. **TERMS AND CONDITIONS OF RESTRICTED STOCK AWARDS.**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4. If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a).

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 9.7. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4 and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

9.7 **Nontransferability of Restricted Stock Award Rights.** Prior to the issuance of shares of Stock pursuant to a Restricted Stock Award, rights to acquire such shares shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or the laws of descent and distribution. All rights with respect to a Restricted Stock Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

10. **TERMS AND CONDITIONS OF PERFORMANCE AWARDS.**

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2, on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to “performance-based compensation” is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award Formula shall not be changed during the Performance Period. The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained (“ **Performance Targets** ”) with respect to one or more measures of business or financial performance (each, a “ **Performance Measure** ”), subject to the following:

(a) **Performance Measures.** Performance Measures shall have the same meanings as used in the Company’s financial statements, or, if such terms are not used in the Company’s financial statements, they shall have the meaning applied pursuant to generally accepted accounting principles, or as used generally in the Company’s industry. Performance Measures shall be calculated with respect to the Company and each Subsidiary Corporation consolidated therewith for financial reporting purposes or such division or other business unit as may be selected by the Committee. For purposes of the Plan, the Performance Measures applicable to a Performance Award shall be calculated in accordance with generally accepted accounting principles, but prior to the accrual or payment of any Performance Award for the same Performance Period and excluding the effect (whether positive or negative) of any change in accounting standards or any extraordinary, unusual or nonrecurring item, as determined by the Committee, occurring after the establishment of the Performance Goals applicable to the Performance Award. Each such adjustment, if any, shall be made solely for the purpose of providing a consistent basis from period to period for the calculation of Performance Measures in order to prevent the dilution or enlargement of the Participant’s rights with respect to a Performance Award. Performance Measures may be one or more of the following, as

determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity; (xii) return on capital; (xiii) return on net assets; (xiv) economic value added; and (xv) market share; (xvi) customer service; (xvii) customer satisfaction; (xviii) safety; (xix) total shareholder return; or (xx) such other measures as determined by the Committee consistent with this Section 10.4(a).

(b) **Performance Targets.** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 Settlement of Performance Awards.

(a) **Determination of Final Value.** As soon as practicable, but no later than the 15th day of the third month following the completion of the Performance Period applicable to a Performance Award, the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable Performance Award Formula.

(b) **Discretionary Adjustment of Award Formula.** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute “qualified performance based compensation” to a “covered employee” within the meaning of Section 162(m) (a “**Covered Employee**”) to reflect such Participant’s individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) **Payment in Settlement of Performance Awards.** As soon as practicable following the Committee’s determination and certification in accordance with Sections 10.5 (a) and (b) but, in any case, no later than the 15th day of the third month following completion of the Performance Period applicable to a Performance Award, payment shall be made to each eligible Participant (or such Participant’s legal representative or other person who acquired the right to receive such payment by reason of the Participant’s death) of the final value of the Participant’s Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share

Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents may be paid currently or may be accumulated and paid to the extent that Performance Shares become nonforfeitable, as determined by the Committee in accordance with Section 409A of the Code. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5. Dividend Equivalents shall not be paid with respect to Performance Units. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, appropriate adjustments shall be made in the Participant's Performance Share Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Performance Share Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) **Death or Disability.** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5.

(b) **Other Termination of Service.** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of an involuntary termination of the Participant's Service, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award.

10.8 **Nontransferability of Performance Awards.** Prior to settlement in accordance with the provisions of the Plan, no Performance Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Performance Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

11. **TERMS AND CONDITIONS OF RESTRICTED STOCK UNIT AWARDS.**

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 . If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) .

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4 , as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award,

provided that Dividend Equivalents may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, appropriate adjustments shall be made in the Participant's Restricted Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award, and all such new, substituted or additional securities or other property shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 Effect of Termination of Service. Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 Settlement of Restricted Stock Unit Awards. The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

11.6 Nontransferability of Restricted Stock Unit Awards. Prior to the issuance of shares of Stock in settlement of a Restricted Stock Unit Award, the Award shall not be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Restricted Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

12. DEFERRED COMPENSATION AWARDS.

12.1 Establishment of Deferred Compensation Award Programs. This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted

automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Participants designated by the Committee who are Insiders or otherwise among a select group of highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) ***Vesting Conditions*** . Deferred Compensation Awards shall not be subject to any vesting conditions.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, a Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2 , appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12 , shall specify at the time of such

election a settlement date with respect to such Award in accordance with rules established by the Committee. The Company shall issue to the Participant upon the earlier of the settlement date elected by the Participant or the date of the Participant's Separation from Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. Such shares of Stock shall be fully vested, and the Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

(iii) **Nontransferability of Stock Unit Awards.** Prior to their settlement in accordance with the provision of the Plan, no Stock Unit Award shall be subject in any manner to anticipation, alienation, sale, exchange, transfer, assignment, pledge, encumbrance, or garnishment by creditors of the Participant or the Participant's beneficiary, except transfer by will or by the laws of descent and distribution. All rights with respect to a Stock Unit Award granted to a Participant hereunder shall be exercisable during his or her lifetime only by such Participant or the Participant's guardian or legal representative.

13. **OTHER STOCK-BASED AWARDS.**

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate.

14. **CHANGE IN CONTROL.**

14.1 **Effect of Change in Control on Options and SARs.** In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror"), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Options or SARs or substitute for outstanding Options or SARs substantially equivalent options or SARs covering the Acquiror's stock. Any Options or SARs which are neither assumed or continued by the Acquiror in connection with the Change in Control nor exercised as of the Change in Control shall, contingent on the Change in Control, become fully vested and exercisable immediately prior to the Change in Control. Options and SARs which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability in connection with the Participant's subsequent termination of Service as the Board may determine.

14.2 **Effect of Change in Control on Other Awards.** In the event of a Change in Control, the Acquiror may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards other than Options or SARs or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Any such Awards which are neither assumed or continued by the Acquiror in connection with the Change in Control shall, contingent on the Change in Control, become fully vested. Awards which are assumed or continued in connection with a Change in Control shall be subject to such

additional accelerated vesting or lapse of restrictions in connection with the Participant's subsequent termination of Service as the Board may determine.

14.3 **Nonemployee Director Awards** . Notwithstanding the foregoing, Nonemployee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **COMPLIANCE WITH SECURITIES LAW** .

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect thereto as may be requested by the Company.

16. **TAX WITHHOLDING** .

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan until the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. The Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates.

17. **Amendment or Termination of Plan.**

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, and (c) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. **MISCELLANEOUS PROVISIONS.**

18.1 **Repurchase Rights.** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5, shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in Section 4.2 or another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability** . If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

18.10 **Section 409A of the Code.** Notwithstanding anything to the contrary in the Plan, to the extent any Award payable in connection with a Participant's Separation from Service constitutes deferred compensation subject to (and not exempt from) Section 409A of the Code

and (ii) the Participant is deemed at the time of such separation to be a "specified employee" under Section 409A of the Code and the Treasury regulations thereunder, then payment shall not be made or commence until the earlier of (i) six (6)-months after such Separation from Service or (ii) the date of the Participant's death following such Separation from Service; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the Participant, including (without limitation) the additional twenty percent (20%) tax for which the Participant would otherwise be liable under Section 409A(a)(1)(B) of the Code in the absence of such delay. Upon the expiration of the applicable delay period, any payment which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the Participant or the Participant's beneficiary in one lump sum on the first business day immediately following such delay.

This document constitutes part of a Prospectus covering securities that have been registered under the Securities Act of 1933, as amended.

**PG&E CORPORATION
AMENDMENT TO RESTRICTED STOCK AGREEMENTS**

PG&E CORPORATION, a California corporation, hereby amends the terms and conditions of the Restricted Stock Agreement(s) relating to the Restricted Stock Award(s) listed below, which was/were granted to the Recipient named below under the PG&E Corporation Long-Term Incentive Program and the PG&E Corporation 2006 Long-Term Incentive Plan (each an "LTIP"). These amendments are effective as of November 17, 2008.

Name of Recipient: _____

Last Four Digits of Recipient's Social Security Number: _____

Affected Restricted Stock Award(s):

DATE OF GRANT	NUMBER OF SHARES GRANTED	NUMBER OF UNVESTED SHARES AS OF 11/1/08

The section of the Restricted Stock Agreement(s) entitled "Release of Shares and Withholding Taxes" is amended to read as follows:

Release of Shares and Withholding Taxes

When the restrictions as to your shares of Restricted Stock lapse, the vested shares shall be delivered to you, within thirty (30) days of the applicable vesting date. You must elect one of the following methods to satisfy applicable withholding and other taxes before the vested shares will be delivered to you:

- Pay the amount due by cash or check,
- Surrender to PG&E Corporation a number of vested shares having an aggregate value (based on the closing price of PG&E Corporation common stock on the New York Stock Exchange on the date of surrender) equal to the amount due.
- Sell your vested shares and use a portion of the sales proceeds to pay the amount due.

You must sign the attached election form indicating which method you elect and return the signed form to the Senior Manager of Executive Compensation, Human Resources by December 1, 2008.

All other terms of the affected Restricted Stock Agreement(s) remain unchanged, except to the extent changes are necessary or appropriate to conform with the above amendments.

The affected Restricted Stock Agreement(s), together with these amendments, constitute the entire understanding between you and PG&E Corporation regarding the Restricted Stock Awards listed above, subject to the terms of the applicable LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of the Restricted Stock Agreement(s), as amended, and the applicable LTIP, the LTIP shall govern. In the event of any conflict or inconsistency between the provisions of the Restricted Stock Agreement(s), as amended, and the PG&E Corporation Officer Severance Policy, the Restricted Stock Agreement(s), as amended, shall govern.

PG&E CORPORATION

ELECTION OF METHOD TO SATISFY APPLICABLE WITHHOLDING TAXES

Name of Award
Recipient

I received the following award(s) of PG&E Corporation common stock (the "Shares") subject to the restrictions and terms of the applicable Restricted Stock Agreement(s):

DATE OF GRANT	NUMBER OF SHARES GRANTED	NUMBER OF UNVESTED SHARES AS OF 11/1/08
January 3, 2005		
January 3, 2006	[xx,xxx]	
January 3, 2007	[xx,xxx]	
[Others?]		

I elect to satisfy applicable withholding taxes as they may become due as the restrictions on the Shares lapse in the following manner:

- ☐ Pay the amount due by cash or check.
- ☐ Surrender to PG&E Corporation a number of vested Shares having an aggregate value (based on the closing price of PG&E Corporation common stock on the New York Stock Exchange on the date of surrender) equal to the amount due.
- ☐ Sell the vested Shares and use a portion of the sales proceeds to pay the amount due.
(You cannot make this election if you have previously entered into a Rule 10b5-1 sales plan that covers the vested Shares.)

To be effective, I understand that this election must be delivered to the Senior Manager, Executive Compensation, PG&E Corporation, One Market, Spear Tower, Suite 400, San Francisco, California 94105 by December 1, 2008.

(Date)

(Signature)

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

**AMENDMENT AND RESTATEMENT OF
PERFORMANCE SHARE AGREEMENT**

PG&E CORPORATION, a California corporation, hereby amends and restates the terms and conditions of the Performance Share Agreements granting Performance Shares on January 3, 2006 under the PG&E Corporation 2006 Long-Term Incentive Plan (the “LTIP”). The terms and conditions of the amended and restated Performance Share Agreements are set forth below:

The LTIP and Other Agreements This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern.

For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Performance Shares PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Performance Shares As long as you remain employed with PG&E Corporation, the Performance Shares will vest on the first business day of January (the “Vesting Date”) of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

Payment of Performance Shares Upon the Vesting Date, PG&E Corporation’s total shareholder return (TSR) will be compared to the TSR of the twelve other companies in PG&E Corporation’s comparator group ¹ for the prior three calendar years (the “Performance Period”). Subject to rounding considerations, there will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR at the 90th percentile or greater will result in a 200% payout of Performance Shares. The following table sets forth the payout percentages for the various TSR rankings that could be achieved:

Number of Companies in Total (Including PG&E)		
13		
Rank	Performance Percentile	Rounded Payout
1	100%	200%
2	92%	170%
3	83%	130%
4	75%	100%
5	67%	90%
6	58%	75%
7	50%	65%
8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%
13	0%	0%

The payment will equal the product of the number of vested Performance Shares, the applicable payout percentage, and the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days of the year preceding the Vesting Date as reported on the New York Stock Exchange. Payments will be made as soon as practicable following the Vesting Date, but in event within sixty (60) days of the Vesting Date.

Dividends Each time that PG&E Corporation declares a dividend on its shares of common stock, an amount equal to the dividend multiplied by the number of Performance Shares granted to you by this Agreement shall be accrued on your behalf. If you receive a Performance Share payout in accordance with the preceeding paragraph, at that same time you also shall receive a cash payment equal to the amount of any dividends accrued over the Performance Period multiplied by the same payout percentage used to determine the amount of the Performance Share payout.

Voluntary Termination If you terminate your employment with PG&E Corporation voluntarily before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited.

Termination for Cause If your employment with PG&E Corporation is terminated by PG&E Corporation for cause before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your

Performance Shares shall be forfeited. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

Termination other than for Cause

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Retirement

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be payable, if at all, as soon as practicable following the Vesting Date, but in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Death/Disability

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall immediately vest and will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination Due to Disposition of Subsidiary

If (1) your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Code or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Withholding Taxes

PG&E Corporation will withhold amounts necessary to satisfy applicable taxes from the payment to be made with respect to your Performance Shares. You will receive the remaining proceeds in cash.

Change in Control

All of your outstanding Performance Shares shall automatically vest, and become nonforfeitable if there is a Change in Control of PG&E Corporation before the Vesting Date. Such vested Performance Shares will become payable on the first business day of the year following such Change in Control if such Change in Control results in a change in the ownership of effective control of PG&E Corporation, or a change in a substantial portion of the assets of PG&E Corporation within the meaning of Code Section 409A(a)(2)(A)(v) and the related regulations (a “409A Change in Control Event”). If the change in control does not result in a 409A Change in Control Event, then payment shall be made as soon as practicable following the Vesting Date and in any event within sixty (60) days of the Vesting Date. The payment, if any, will be based on PG&E Corporation’s TSR for the period from the date of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation’s comparator group ² for the same period. The payment will be calculated by multiplying the number of vested Performance Shares by the payout percentage. The resulting number of Performance Shares will be multiplied by the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the Change in Control as reported on the New York Stock Exchange. At the same time, you shall also receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation (or any of its subsidiaries) sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination.”

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

¹ The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

² The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

**AMENDED AND RESTATED
PERFORMANCE SHARE AGREEMENT**

PG&E CORPORATION, a California corporation, hereby amends and restates the terms and conditions of Performance Share Agreements granting Performance Shares on January 3, 2007 under the PG&E Corporation 2006 Long-Term Incentive Plan as amended (the “LTIP”). The terms and conditions of the amended and restated Performance Share Agreements are set forth below:

The LTIP and Other Agreements This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP.

For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Performance Shares PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Performance Shares As long as you remain employed with PG&E Corporation, the Performance Shares will vest on the first business day of January (the “Vesting Date”) of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

Payment of Performance Shares Upon the Vesting Date, PG&E Corporation’s total shareholder return (TSR) will be compared to the TSR of the twelve other companies in PG&E Corporation’s comparator group ¹ for the prior three calendar years (the “Performance Period”). Subject to rounding considerations, there will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR in the top rank will result in a 200% payout of Performance Shares. The following table sets forth the payout percentages for the various TSR rankings that could be achieved:

Number of Companies in Total (Including PG&E)		
13		
Rank	Performance Percentile	Rounded Payout
1	100%	200%
2	92%	170%
3	83%	130%
4	75%	100%
5	67%	90%
6	58%	75%
7	50%	65%
8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%
13	0%	0%

The payment will equal the product of the number of vested Performance Shares, the applicable payout percentage, and the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days of the year preceding the Vesting Date as reported on the New York Stock Exchange. Payments, if any, will be made as soon as practicable after the Vesting Date following the date that the Compensation Committee of the PG&E Corporation Board of Directors certifies the TSR percentile rank over the Performance Period pursuant to Section 10.5(a) of the LTIP, but in any event within sixty (60) days after the Vesting Date.

Dividends Each time that PG&E Corporation declares a dividend on its shares of common stock, an amount equal to the dividend multiplied by the number of Performance Shares granted to you by this Agreement shall be accrued on your behalf. If you receive a Performance Share payout in accordance with the preceding paragraph, at that same time you also shall receive a cash payment equal to the amount of any dividends accrued over the Performance Period multiplied by the same payout percentage used to determine the amount of the Performance Share payout.

Voluntary Termination If you terminate your employment with PG&E Corporation voluntarily before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited.

Termination for Cause If your employment with PG&E Corporation is terminated by PG&E Corporation for cause before the Vesting Date, all of the

Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

Termination other than for Cause

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Retirement

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be payable, if at all, as soon as practicable following the Vesting Date, but in any event within sixty (60) days of the Vesting Date. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Death/Disability

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall immediately vest and will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination Due to Disposition of Subsidiary

(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended, or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Change in Control

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement. If the Acquiror assumes or continues PG&E Corporation’s rights and obligations under this Agreement or substitutes a substantially equivalent award, TSR shall be calculated by aggregating (a) the TSR of PG&E Corporation for the period from January 1 of the year of grant to the date of the Change in Control, and (b) the TSR of the Acquiror from the date of the Change in Control to the Vesting Date. The payout percentage reflected in the table set forth above for the highest percentile TSR performance met or exceeded when calculated on that basis, and considering any adjustments to the comparator group, will be used to determine the amount of the payout, if any, upon settlement of the assumed, continued or substituted award which settlement shall occur as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

If this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement, all of your outstanding Performance Shares shall automatically vest and become nonforfeitable when the Change in Control of PG&E Corporation occurs before the Vesting Date. Such vested Performance Shares will become payable as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the original Vesting Date. The payment, if any, will be based on PG&E Corporation’s TSR for the period from January 1 of the year of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation’s comparator group ² for the same period. The payment will be calculated by multiplying the number of vested Performance Shares by the payout percentage. The resulting number of Performance Shares will be multiplied by the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the Change in Control as reported on the New York Stock Exchange. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination In Connection with a Change in Control

If your employment is terminated in connection with a Change in Control within three months before the Change in Control occurs or within two years following the Change in Control, all of your outstanding Performance Shares (to the extent they did not previously vest upon failure of the Acquiror to assume or continue this Award) shall automatically vest and become nonforfeitable on the date of termination of your employment. Your vested Performance Shares will be payable, if at all, as

soon as practicable following the original Vesting Date and in any event within sixty (60) days of the Vesting Date and will be based on the same formula applied to active employees. You shall also at that time receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Withholding Taxes

PG&E Corporation will withhold amounts necessary to satisfy applicable taxes from the payment to be made with respect to your Performance Shares. You will receive the remaining proceeds in cash.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination.”

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

¹ The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

² The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

**AMENDMENT AND RESTATEMENT OF
PERFORMANCE SHARE AGREEMENT**

PG&E CORPORATION, a California corporation, hereby amends and restates the terms and conditions of Performance Share Agreements granting Performance Shares on March 3, 2008 under the PG&E Corporation 2006 Long-Term Incentive Plan as amended (the “LTIP”). The terms and conditions of the amended and restated Performance Share Agreements are set forth below.

The LTIP and Other Agreements This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP.

For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Performance Shares PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Performance Shares As long as you remain employed with PG&E Corporation, the Performance Shares will vest on the first business day of March (the “Vesting Date”) of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

Payment of Performance Shares Upon the Vesting Date, PG&E Corporation’s total shareholder return (TSR) will be compared to the TSR of the twelve other companies in PG&E Corporation’s comparator group ¹ for the prior three calendar years (the “Performance Period”). Subject to rounding considerations, there will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR in the top rank will result in a 200% payout of Performance Shares. The following table sets forth the payout percentages for the various TSR rankings that could be achieved:

Number of Companies in Total (Including PG&E)		
13		
Rank	Performance Percentile	Rounded Payout
1	100%	200%
2	92%	170%
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4	75%	100%
5	67%	90%
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8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%
13	0%	0%

The payment will equal the product of the number of vested Performance Shares, the applicable payout percentage, and the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days of the year preceding the Vesting Date as reported on the New York Stock Exchange. Payments, if any, will be made as soon as practicable after the Vesting Date following the date that the Compensation Committee of the PG&E Corporation Board of Directors certifies the TSR percentile rank over the Performance Period pursuant to Section 10.5(a) of the LTIP, but in any event within sixty (60) days of the Vesting Date.

Dividends Each time that PG&E Corporation declares a dividend on its shares of common stock, an amount equal to the dividend multiplied by the number of Performance Shares granted to you by this Agreement shall be accrued on your behalf. If you receive a Performance Share payout in accordance with the preceding paragraph, at that same time you also shall receive a cash payment equal to the amount of any dividends accrued over the Performance Period multiplied by the same payout percentage used to determine the amount of the Performance Share payout.

Voluntary Termination If you terminate your employment with PG&E Corporation voluntarily before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited.

Termination for Cause If your employment with PG&E Corporation is terminated by PG&E Corporation for cause before the Vesting Date, all of the

Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

Termination other than for Cause

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, as soon as practicable after the Vesting Date based on the same formula applied to active employees and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Retirement

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be payable, if at all, as soon as practicable following the Vesting Date and in any event within sixty (60) days of the Vesting Date. At the same time you also shall also receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Death/Disability

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall immediately vest and will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination Due to Disposition of Subsidiary

(1) If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended, or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be payable, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date, based on the same formula applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Change in Control

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement. If the Acquiror assumes or continues PG&E Corporation’s rights and obligations under this Agreement or substitutes a substantially equivalent award, TSR shall be calculated by aggregating (a) the TSR of PG&E Corporation for the period from January 1 of the year of grant to the date of the Change in Control, and (b) the TSR of the Acquiror from the date of the Change in Control to the last calendar day of the year preceding the Vesting Date. The payout percentage reflected in the table set forth above for the highest percentile TSR performance met or exceeded when calculated on that basis, and considering any adjustments to the comparator group, will be used to determine the amount of the payout, if any, upon settlement of the assumed, continued or substituted award, which settlement shall occur as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

If this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement, all of your outstanding Performance Shares shall automatically vest and become nonforfeitable when the Change in Control of PG&E Corporation occurs before the Vesting Date. Such vested Performance Shares will become payable as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the original Vesting Date. The payment, if any, will be based on PG&E Corporation’s TSR for the period from January 1 of the year of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation’s comparator group² for the same period. The payment will be calculated by multiplying the number of vested Performance Shares by the payout percentage. The resulting number of Performance Shares will be multiplied by the average closing price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the Change in Control as reported on the New York Stock Exchange. At the same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the first business day of the year following the Change in Control multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

Termination In Connection with a Change in Control

If your employment is terminated in connection with a Change in Control within three months before the Change in Control occurs or within two years following the Change in Control, all of your outstanding Performance Shares (to the extent they did not previously vest upon failure of the Acquiror to assume or continue this Award) shall automatically vest and become nonforfeitable on the date of termination of your employment. Your vested Performance Shares will be payable, if at all, as

soon as practicable following the original Vesting date and in any event within sixty (60) days of the Vesting Date and will be based on the same formula applied to active employees. You shall also at that time receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same payout percentage used to determine the amount, if any, of the Performance Share payout.

PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Withholding Taxes

PG&E Corporation will withhold amounts necessary to satisfy applicable taxes from the payment to be made with respect to your Performance Shares. You will receive the remaining proceeds in cash.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination.”

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

By signing the cover sheet of this Agreement, you agree to all of the terms and conditions described above and in the LTIP.

¹ The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

² The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

PG&E CORPORATION
EXECUTIVE STOCK OWNERSHIP PROGRAM

Administrative Guidelines
(As amended effective February 17, 2009)

1. Description. The Executive Stock Ownership Program (“Program”) was approved by the Nominating and Compensation Committee of the Board of Directors on October 15, 1997. The Program is an important element of the Committee’s compensation policy of aligning executive interests with those of the Corporation’s shareholders. As an integral part of the Program, the Committee also authorized the use of Special Incentive Stock Ownership Premiums (“SISOPs”) which are designed to provide incentives to Eligible Executives to assist in achieving minimum stock ownership targets established by the Committee. These Guidelines were originally adopted by the Committee on November 19, 1997, amended by the Committee on July 22, 1998, October 21, 1998, February 16, 2000, September 19, 2000, February 19, 2003, February 15, 2006, effective January 1, 2009, and February 17, 2009. These amended Guidelines, along with the written materials provided to the Committee on October 15, 1997, describe the Program which became effective on January 1, 1998. The Program is administered by the Corporation’s Senior Human Resources Officer.

2. Eligible Executives. The Chief Executive Officer shall designate the officers of the Corporation and its affiliates who shall be Eligible Executives covered by the Program. The officers covered by the Guidelines and the applicable total stock ownership target (“Target”) are:

Officer Band	Position	Total Stock Ownership Target
1	CEO	3 x base salary
2	Heads of Business Lines, CFO, & General Counsel	2 x base salary
3	SVPs of Corp. & Utility	1.5 x base salary

3. Annual Milestones. Under the Guidelines, Targets are designed to be achieved by the end of the fifth calendar year following the calendar year in which an officer first becomes an Eligible Executive (“Target Date”). Annual Milestones have been established as a means of measuring progress towards achieving Targets and of providing incentives for Eligible Executives to expeditiously meet their Targets. The Annual Milestone at the end of the first full calendar year is 20 percent of the Target, and the Annual Milestone for each succeeding year is an additional 20 percent of the Target. Annual Milestones shall be adjusted to reflect changes in base salary; provided, however, that in each instance any such modification shall be amortized over the remaining original five-year term. Following the Target Date, Targets also shall be modified to reflect changes in base salary.

4. Calculation of Stock Ownership Levels. Stock ownership level is the dollar value of stock and stock equivalents owned by an Eligible Executive and calculated as of the last day of the calendar year ("Measurement Date"). The purpose of this calculation is to determine the value of the stock or stock equivalents owned by the Eligible Executive as compared with the Annual Milestone or Target for that executive. For purposes of this calculation, the value per share of stock or stock equivalent ("Measurement Value") is the average closing price of PG&E Corporation common stock as traded on the New York Stock Exchange for the last thirty (30) trading days of the year.
- a) The value of stock beneficially owned by the Eligible Executive is determined by multiplying the number of shares owned beneficially on the Measurement Date times the Measurement Value.
 - b) The value of PG&E Corporation phantom stock units credited to the Eligible Executive's account in the PG&E Corporation Supplemental Retirement Savings Plan ("SRSP") is determined by multiplying the number of phantom stock units credited to the Eligible Executive's SRSP account on the Measurement Date times the Measurement Value.
 - c) The value of stock held in the PG&E Corporation stock fund of any defined contribution plan maintained by PG&E Corporation or any of its subsidiaries is determined by multiplying the number of shares in such plan on the Measurement Date times the Measurement Value.
 - d) The value of restricted stock held by the Eligible Executive is determined by multiplying the number of shares held by the Eligible Executive on the Measurement Date times the Measurement Value (for purposes of this calculation, restricted stock shall include any shares that have been approved by the Compensation Committee but not yet issued as of the Measurement Date).
 - e) The value of unvested restricted stock units held by the Eligible Executive on the Measurement Date is determined by multiplying the number of outstanding restricted stock units held by the Eligible Executive on the Measurement Date times the Measurement Value (for purposes of this calculation, restricted stock units shall include any units that have been approved by the Compensation Committee but not yet issued as of the Measurement Date).
5. Award of SISOPs. SISOPs are awarded to Eligible Executives who achieve and maintain stock ownership levels prior to the end of the third year following the year in which an officer first became an Eligible Executive. For purposes of determining awards, the total stock ownership level is calculated as set forth under paragraph 4 on the Measurement Date; however, such calculations will exclude the value of restricted stock held by the Eligible Executive as defined in paragraph 4(d) and will exclude the value of restricted stock units held by the Eligible Executive as defined in paragraph 4(e). The amount of a SISOP award shall be equal to:
- a) For the first year, 20 percent of the amount of the Eligible Executive's stock ownership level at the end of the year, up to the Annual Milestone, plus an additional 30 percent of the amount by which the stock ownership level exceeds the Annual Milestone up to the Target; and

- b) For each of the second and third years, the current stock ownership level is reduced by the stock ownership level used to calculate previous SISOP awards to determine the new ownership, then 20 percent of the amount up to the Annual Milestone by which the end of the year stock ownership level exceeds the beginning of the year stock ownership level, plus an additional 30 percent of the amount by which the end of the year balance exceeds the Annual Milestone, up to the Target.

Each time a SISOP award calculation is made, a second calculation also is made to determine the minimum number of shares which must be retained by the Eligible Executive to avoid forfeiture of the SISOP award ("Minimum Ownership Level") as discussed below in paragraph 8. This calculation converts the dollar value of the stock ownership level used as the basis for qualifying for SISOPs into a number of shares of stock by dividing that stock ownership level by the Measurement Value. Thus, for example, if an Eligible Executive's stock ownership level (less restricted stock and restricted stock units held by the Eligible Executive) was \$250,000 and the Measurement Value was \$25 per share, then the Minimum Ownership Level would be 10,000 shares.

For purposes of this calculation, the maximum share ownership level used is the Eligible Executive's Target. If an Eligible Executive has a share ownership level higher than his/her Target, the increment over the Target is not included. Thus, for example, if an Eligible Executive has a Target of \$750,000 and his/her share ownership level is \$900,000, then only \$750,000 is used to calculate the Minimum Ownership Level.

6. SISOPs Credited to the SRSP. Upon award, SISOPs are credited to the Eligible Executive's SRSP account and converted into units of phantom stock each equal in value to a share of PG&E Corporation common stock ("SISOP units") as determined in accordance with the SRSP. The SISOP units constitute "incentive awards" authorized to be awarded by the Committee to Eligible Executives under the PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP"). Upon credit of SISOP units to an Eligible Executive's SRSP account, an equal number of shares of PG&E Corporation common stock shall be reserved for issuance from the pool of shares authorized for issuance under the 2006 LTIP. Once a SISOP unit is credited to the Eligible Executive's SRSP account, it shall be subject to all of the terms and conditions specifically applicable to SISOP units under the SRSP. Once vested in accordance with paragraph 7 below, SISOP units are distributed in the form of an equal number of shares of PG&E Corporation common stock as provided in the SRSP.
7. Vesting. SISOPs vest only upon the expiration of three years after the date of award (provided the Eligible Executive continues to be employed on such date). An Eligible Executive's unvested SISOPs will be forfeited upon termination of employment except as otherwise provided in the Vesting Guidelines in effect on the grant date for a particular award.
8. Forfeiture of SISOP Units. So long as SISOP units remain unvested, such units are subject to forfeiture if, on each Measurement Date, the Eligible Executive's stock ownership is less than the Minimum Ownership Level established when the SISOPs were granted (see paragraph 5). To determine forfeiture, the following steps are followed on each Measurement Date:

- a) The total stock and stock equivalents owned by an Eligible Executive is determined as set forth under paragraph 4, excluding sections 4(d) and 4(e). This total ("Current Holdings") is compared with the Minimum Ownership Level determined when the SISOPs were granted. If the Current Holdings are equal to or greater than the Minimum Ownership Level, then no unvested SISOP units are forfeited. If the Current Holdings are less than the Minimum Ownership Level, then the unvested SISOP units are forfeited in the same proportion as the Current Holdings are less than Minimum Ownership Level (for example, if the Current Holdings are 20 percent less than the Minimum Ownership Level, then 20 percent of the SISOP units are forfeited).
9. Failure to Achieve or Maintain Target. Failure to achieve stock ownership levels at Target on the Target Date, or to maintain stock ownership levels at Target on any Measurement Date thereafter, will result in the deferral into the PG&E Corporation Phantom Stock Fund of the SRSP of awards from the PG&E Corporation Long-Term Incentive Program and/or 2006 LTIP that are settled only in cash ("Cash-Settled Awards") and the Short-Term Incentive Plan ("STIP"). As of the Target Date or any Measurement Date, to the extent that stock ownership levels are below Target, the Cash-Settled Award or STIP award (in an amount determined by PG&E Corporation in its sole discretion) shall be converted into phantom stock units, to the extent necessary to achieve the Target stock ownership level. Such conversion of Cash-Settled Awards and STIP awards shall continue for successive Measurement Dates, if necessary, until Target is met. Phantom stock units attributable to Cash-Settled Awards and STIP awards described in this paragraph 9 will be paid from the SRSP in a lump sum in accordance with Section 7(a) of the SRSP. Notwithstanding anything to the contrary set forth in this Section 9, the deferral provisions of this Section 9 shall be applied only with respect to Cash-Settled Awards and STIP awards that can be deferred in accordance with the initial deferral election rules of Section 409A of the Internal Revenue Code of 1986 determined as if the Eligible Executive had made a deferral election on the Target Date or Measurement Date, as applicable, and the Eligible Executive shall be deemed to have made the election hereunder on the applicable Target Date or Measurement Date by failing to achieve the applicable stock ownership levels.

PG&E CORPORATION
OFFICER SEVERANCE POLICY
(As Amended Effective as of January 1, 2009)

1. Purpose. This is the controlling and definitive statement of the Officer Severance Policy of PG&E Corporation (“Policy”). Since Officers are employed at the will of PG&E Corporation (“Corporation”) or a participating employer (“Employer”), their employment may be terminated at any time, with or without cause. A list of Employers is attached hereto as Appendix A. The Policy, which was first adopted effective November 1, 1998, provides Officers of the Corporation and Employers in Officer Compensation Bands I through V (“Officers”) with severance benefits if their employment is terminated.¹ Severance benefits for officers not covered by this Policy will be provided under policies or programs developed by the appropriate lines of business in consultation with and with the approval by the Senior Human Resources Officer of the Corporation. For the avoidance of doubt, the revisions made to this Policy relating to Code Section 409A (defined below), apply to all Officers including those that may be covered under prior provisions of the Policy as required by Section 6 hereof.

The purpose of the Policy is to attract and retain senior management by defining terms and conditions for severance benefits, to provide severance benefits that are part of a competitive total compensation package, to provide consistent treatment for all terminated officers, and to minimize potential litigation costs associated with Officer termination of employment.

2. Termination of Employment Not Following a Change in Control or Potential Change in Control.

(a) Corporation or Employer’s Obligations. If the Corporation or an Employer exercises its right to terminate an Officer’s employment without cause and such termination does not entitle Officer to payments under Section 3, the Officer shall be given thirty (30) days’ advance written notice or pay in lieu thereof (which shall be paid in a lump sum together with the payment described in Section 2(a)(1) below). Except as provided in Section 2(b) below, in consideration of the Officer’s agreement to the obligations described in Section 2(d) below and to the arbitration provisions described in Section 12 below, the following payments and benefits shall also be provided to Officer following Officer’s separation from service (within the meaning of Code Section 409A):²

(1) A lump sum severance payment equal to: 1/12 (the sum of the Officer’s annual base compensation and the Officer’s Short-Term Incentive Plan target award at the time.

¹ Severance benefits for Officers who are currently covered by an employment agreement will continue to be provided solely under such agreements until their expiration at which time this Policy will become effective for such Officers. If an employee becomes a covered Officer under this Policy as a result of a promotion, if such Officer was then covered by a severance arrangement subject to Section 409A of the Internal Revenue Code of 1986 (“Code Section 409A”), the severance benefits under this Policy provided to such person shall comply with the time and form of payment provisions of such prior severance arrangement, to the extent required by Code Section 409A.

² Any payments made hereunder shall be less applicable taxes.

of his or her termination) times (the number of months that Officer was employed by the Corporation or the Employer (“ Severance Multiple ”)); provided, however, that the Severance Multiple shall be no less than 6, nor more than 24 for Officers in Officer Bands I, II, III, or more than 18 for Officers in Officer Bands IV or V. Annual base compensation shall mean the Officer’s monthly base pay for the month in which the Officer is given notice of termination, multiplied by 12. The payment described in this Section 2(a)(1) shall be made in a single lump sum as soon as practicable following the date the release of claims described in Section 2(d)(1) becomes effective, provided that payment shall in no event be made later than the 15th day of the third month following the later of the end of the calendar year or the Corporation’s taxable year in which the Officer’s separation from service occurs .

(2) Except as otherwise set forth in the applicable award agreement or as otherwise required by applicable law, the equity-based incentive awards granted to Officer under the Corporation’s Long-Term Incentive Program which have not yet vested as of the date of termination will continue to vest over a period of months equal to the Severance Multiple after the date of termination as if the Officer had remained employed for such period. Except as otherwise set forth in the applicable award agreement, for vested stock options as of the date of termination, the Officer shall have the right to exercise such stock options at any time within their respective terms or within five years after termination, whichever is shorter. Except as otherwise set forth in the applicable award agreement, for stock options that vest during a period of months equal to the Severance Multiple, the Officer shall have the right to exercise such options at any time within five years after termination , subject to the term of the options . Except as otherwise set forth in the applicable award agreement, any unvested equity-based incentive awards remaining at the end of such period shall be forfeited;

(3) For Officers in Officer Bands I, II or III, two thirds of the unvested Company stock units in the Officer’s account in the Corporation’s Deferred Compensation Plan for Officers which were awarded in connection with the Executive Stock Ownership Program requirements (“ SISOPs ”) shall vest upon the Officer’s termination, and one third shall be forfeited. For Officers in Officer Bands IV and V, one third of any unvested SISOPs shall vest upon the Officer’s termination, and two thirds shall be forfeited. Unvested stock units attributable to SISOPs which become vested under this provision shall be distributed to Officer in accordance with the Deferred Compensation Plan after such stock units vest;

(4) For a period of up to 18 months, the Officer’s COBRA premiums (with such payment subject to taxation if required or advisable to avoid violating the nondiscrimination requirements of Code Section 105(h)), if any;

(5) If Officer is terminated after serving consecutively for six months in a fiscal year, Officer shall be entitled to receive a prorated bonus under any short-term incentive plan in which such Officer participates, at the time such bonus , if any, would otherwise be paid ~~–~~(but in any event no later than the 15th day of the third month following the later of the end of the calendar year or the Corporation’s taxable year in which the Officer’s separation from service occurs or in which the right to such payment otherwise ceases to be subject to a substantial risk of forfeiture for purposes of Code Section 409A) ;

(6) To the extent not theretofore paid or provided, the Officer shall be paid or provided with any other amounts or benefits required to be paid or provided or which the Officer is eligible to receive under any plan, contract or agreement of the Corporation or Employer;

(7) Such career transition services as the Corporation's Senior Human Resources Officer shall determine is appropriate (if any), provided that payment of such services will only be made to the extent the Officer actually incurs an expense and then only to the extent incurred and paid within the time limit set forth in Treasury Regulation Section 1.409A-1(b)(9)(v)(E). Any such services, to the extent they are not exempt under Treasury Regulation Section 1.409A-1(b)(9)(v)(A) or (D), shall be structured to comply with the requirements of Treasury Regulation Section 1.409A-3(i)(1)(iv) and, if applicable, shall be subject to the six-month delay described in Code Section 409A(a)(2)(B)(i).

(8) All acts required of the Employer under the Policy may be performed by the Corporation for itself and the Employer, and the costs of the Policy may be equitably apportioned by the Administrator among the Corporation and the other Employers. The Corporation shall be responsible for making payments and providing benefits pursuant to this Policy for Officers employed by the Corporation. Whenever the Employer is permitted or required under the terms of the Policy to do or perform any act, matter or thing, it shall be done and performed by any Officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Employer shall be responsible for making payments and providing benefits pursuant to the Policy on behalf of its Officers or for reimbursing the Corporation for the cost of such payments or benefits, as determined by the Corporation in its sole discretion. In the event the respective Employer fails to make such payment or reimbursement, an Officer's (or other payee's) sole recourse shall be against the respective Employer, and not against the Corporation ;

(b) Remedies . An Officer shall be entitled to recover damages for late or nonpayment of amounts to which the Officer is entitled hereunder. The Officer shall also be entitled to seek specific performance of the obligations and any other applicable equitable or injunctive relief.

(c) Section 2(a) shall not apply in the event that an Officer's employment is terminated "for cause." Except as used in Section 3 of this Policy, "for cause" means that the Corporation, in the case of an Officer employed by the Corporation, or Employer in the case of an Officer employed by an Employer, acting in good faith based upon information then known to it, determines that the Officer has engaged in, committed, or is responsible for (1) serious misconduct, gross negligence, theft, or fraud against the Corporation and/or an Employer; (2) refusal or unwillingness to perform his duties; (3) inappropriate conduct in violation of Corporation's equal employment opportunity policy; (4) conduct which reflects adversely upon, or making any remarks disparaging of, the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries; (5) insubordination; (6) any willful act that is likely to have the effect of injuring the reputation, business, or business relationship of the Corporation or its subsidiaries or affiliates; (7) violation of any fiduciary duty; or (8) breach of any duty of loyalty; or (9) any breach of the restrictive covenants contained in Section 2(d) below. Upon termination "for cause," the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries shall have no liability to the Officer other than for accrued salary,

vacation benefits, and any vested rights the Officer may have under the benefit and compensation plans in which the Officer participates and under the general terms and conditions of the applicable plan.

(d) Obligations of Officer.

(1) Release of Claims. There shall be no obligation to commence the payment of the amounts and benefits described in Section 2(a) until the latter of (1) the delivery by Officer to the Corporation a fully executed comprehensive general release of any and all known or unknown claims that he or she may have against the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries and a covenant not to sue in the form prescribed by the Administrator, and (2) the expiration of any revocation period set forth in the release. The Corporation shall promptly furnish such release to Officer in connection with the Officer's separation from service, and such release must be executed by Officer and become effective during the period set forth in the release as a condition to Officer receiving the payments and benefits described in Section 2(a).

(2) Covenant Not to Compete. (i) During the period of Officer's employment with the Corporation or its subsidiaries and for a period of months equal to the Severance Multiple thereafter (the "Restricted Period"), Officer shall not, in any county within the State of California or in any city, county or area outside the State of California within the United States or in the countries of Canada or Mexico, directly or indirectly, whether as partner, employee, consultant, creditor, shareholder, or other similar capacity, promote, participate, or engage in any activity or other business competitive with the Corporation's business or that of any of its subsidiaries or affiliates, without the prior written consent of the Corporation's Chief Executive Officer. Notwithstanding the foregoing, Officer may have an interest in any public company engaged in a competitive business so long as Officer does not own more than 2 percent of any class of securities of such company, Officer is not employed by and does not consult with, or becomes a director of, or otherwise engage in any activities for, such competing company.

a. The Corporation and its subsidiaries presently conduct their businesses within each county in the State of California and in areas outside California that are located within the United States, and it is anticipated that the Corporation and its subsidiaries will also be conducting business within the countries of Canada and Mexico. Such covenants are necessary and reasonable in order to protect the Corporation and its subsidiaries in the conduct of their businesses. To the extent that the foregoing covenant or any provision of this Section 2(d)(2)a shall be deemed illegal or unenforceable by a court or other tribunal of competent jurisdiction with respect to (i) any geographic area, (ii) any part of the time period covered by such covenant, (iii) any activity or capacity covered by such covenant, or (iv) any other term or provision of such covenant, such determination shall not affect such covenant with respect to any other geographic area, time period, activity or other term or provision covered by or included in such covenant.

(3) Soliciting Customers and Employees. During the Restricted Period, Officer shall not, directly or indirectly, solicit or contact any customer or any prospective customer of the Corporation or its subsidiaries or affiliates for any commercial pursuit that could

be reasonably construed to be in competition with the Corporation, or induce, or attempt to induce, any employees, agents or consultants of or to the Corporation or any of its subsidiaries or affiliates to do anything from which Officer is restricted by reason of this covenant nor shall Officer, directly or indirectly, offer or aid to others to offer employment to, or interfere or attempt to interfere with any employment, consulting or agency relationship with, any employees, agents or consultants of the Corporation, its subsidiaries and affiliates, who received compensation of \$75,000 or more during the preceding six (6) months, to work for any business competitive with any business of the Corporation, its subsidiaries or affiliates.

(4) Confidentiality. Officer shall not at any time (including after termination of employment) divulge to others, use to the detriment of the Corporation or its subsidiaries or affiliates, or use in any business competitive with any business of the Corporation or its subsidiaries or affiliates any trade secret, confidential or privileged information obtained during his employment with the Corporation or its subsidiaries or affiliates, without first obtaining the written consent of the Corporation's Chief Executive Officer. This paragraph covers but is not limited to discoveries, inventions (except as otherwise provided by California law), improvements, and writings, belonging to or relating to the affairs of the Corporation or of any of its subsidiaries or affiliates, or any marketing systems, customer lists or other marketing data. Officer shall, upon termination of employment for any reason, deliver to the Corporation all data, records and communications, and all drawings, models, prototypes or similar visual or conceptual presentations of any type, and all copies or duplicates thereof, relating to all matters contemplated by this paragraph.

(5) Assistance in Legal Proceedings. During the Restricted Period, Officer shall, upon reasonable notice from the Corporation, furnish information and proper assistance (including testimony and document production) to the Corporation as may be reasonably required by the Corporation in connection with any legal, administrative or regulatory proceeding in which it or any of its subsidiaries or affiliates is, or may become, a party, or in connection with any filing or similar obligation of the Corporation imposed by any taxing, administrative or regulatory authority having jurisdiction, provided, however, that the Corporation shall pay all reasonable expenses incurred by Officer in complying with this paragraph within 60 days after Officer incurs such expenses.

(6) Remedies. Upon Officer's failure to comply with the provisions of this Section 2(d), the Corporation shall have the right to immediately terminate any unpaid amounts or benefits described in Section 2(a) to Officer. In the event of such termination, the Corporation shall have no further obligations under this Policy and shall be entitled to recover damages. In the event of an Officer's breach or threatened breach of any of the covenants set forth in this Section 2(d), the Corporation shall also be entitled to specific performance by Officer of any such covenant and any other applicable equitable or injunctive relief.

3. Termination of Employment Following a Change in Control or Potential Change in Control.

(a) If an Executive Officer's employment by the Corporation or any subsidiary or successor of the Corporation shall be subject to an Involuntary Termination within the Covered

Period, then the provisions of this Section 3 instead of Section 2 shall govern the obligations of the Corporation as to the payments and benefits it shall provide to the Executive Officer. In the event that Executive Officer's employment with the Corporation or an employing subsidiary is terminated under circumstances which would not entitle Executive Officer to payments under this Section 3, Executive Officer shall only receive such benefits to which he is entitled under Section 2, if any. In no event shall Executive Officer be entitled to receive termination benefits under both this Section 3 and Section 2.

All the terms used in this Section 3 shall have the following meanings:

(1) " Affiliate " shall mean any entity which owns or controls, is owned or is under common ownership or control with, the Corporation.

(2) " Cause " shall mean (i) the willful and continued failure of the Executive Officer to perform substantially the Executive Officer's duties with the Corporation or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive Officer by the Board of Directors or the Chief Executive Officer of the Corporation which specifically identifies the manner in which the Board of Directors or Chief Executive Officer believes that the Executive Officer has not substantially performed the Executive Officer's duties; or (ii) the willful engaging by the Executive Officer in illegal conduct or gross misconduct which is materially demonstrably injurious to the Corporation.

For purposes of the provision, no act or failure to act, on the part of the Executive Officer, shall be considered "willful" unless it is done, or omitted to be done, by the Executive Officer in bad faith or without reasonable belief that the Executive Officer's action or omission was in the best interests of the Corporation. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board of Directors or upon the instructions of the Chief Executive Officer or a senior officer of the Corporation or based upon the advice of counsel for the Corporation shall be conclusively presumed to be done, or omitted to be done, by the Executive Officer in good faith and in the best interests of the Corporation. The cessation of employment of the Executive Officer shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive Officer a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board of Directors at a meeting of the Board of Directors called and held for such purpose (after reasonable notice is provided to the Executive Officer and the Executive Officer is given an opportunity, together with counsel, to be heard before the Board of Directors), finding that, in the good faith opinion of the Board of Directors, the Executive Officer is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(3) " Change in Control " shall be deemed to have occurred if:

a. any "person" (as such term is used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, but excluding any benefit plan for employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the beneficial owner of securities of the Corporation

representing 20 percent or more of the combined voting power of the Corporation's then outstanding securities;

b. during any two consecutive years, individuals who at the beginning of such a period constitute the Board of Directors of the Corporation cease for any reason to constitute at least a majority of the Board of Directors of the Corporation, unless the election or the nomination for election by the shareholders of the Corporation, of each new Director was approved by a vote of at least two-thirds ($\frac{2}{3}$) of the Directors then still in office who were Directors at the beginning of the period; or

c. any consolidation or merger of the Corporation shall have been consummated other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent of such surviving entity) at least 70 percent of the Combined Voting Power of the Corporation, such surviving entity or the parent of such surviving entity outstanding immediately after such merger or consolidation; or

d. the shareholders of the Corporation shall have approved (i) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Corporation; or (ii) any plan or proposal for the liquidation or dissolution of the Corporation.

(4) "Change in Control Date" shall mean the date on which a Change in Control occurs.

(5) "Combined Voting Power" shall mean the combined voting power of the Corporation's or other relevant entity's then outstanding voting securities.

(6) "Covered Period" shall mean the period commencing with the Change in Control Date and terminating two (2) years following said commencement; provided, however, that if a Change in Control occurs and Executive Officer's employment with the Corporation or the employing subsidiary is subject to an Involuntary Termination before the Change in Control Date but on or after a Potential Change in Control Date, and if it is reasonably demonstrated by the Executive Officer that such termination (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change in Control, or (ii) otherwise arose in connection with or in anticipation of a Change in Control, then the Covered Period shall mean, as applied to Executive Officer, the two-year period beginning on the date immediately before the Potential Change in Control Date.

(7) "Disability" shall mean the absence of the Executive Officer from the Executive Officer's duties with the Corporation or the employing subsidiary on a full-time basis for 180 consecutive business days as a result of incapacity due to physical or mental illness which is determined to be total and permanent by a physician selected by the Corporation or its insurers and acceptable to the Executive Officer or the Executive Officer's legal representative.

(8) “ Executive Officer ” shall mean officers of the Corporation at the level of Senior Vice President and above and the principal executive officer of each Employer.

(9) “ Good Reason ” shall mean any one or more of the following which takes place within the Covered Period:

- a. A material diminution in the Executive Officer’s base compensation;
- b. A material diminution in the Executive Officer’s authority, duties, or responsibilities;
- c. A material diminution in the authority, duties, or responsibilities of the supervisor to whom the Executive Officer is required to report, including a requirement that the Executive Officer report to a corporate officer or employee instead of reporting directly to the Board of Directors of the Corporation (in the case of an Executive Officer reporting to such Board of Directors);
- d. A material diminution in the budget over which the Executive Officer retains authority;
- e. A material change in the geographic location at which the Executive Officer must perform the services; or
- f. Any other action or inaction that constitutes a material breach by the Corporation of this Policy;

provided, however, that the Executive Officer must provide notice to the Corporation of the existence of the applicable condition described in this Section 3(a)(9) within 90 days of the initial existence of the condition, upon the notice of which the Corporation shall have 30 days during which it may remedy the condition and, if remedied, Good Reason shall not exist.

(10) “ Involuntary Termination ” shall mean a termination (i) by the Corporation without Cause, or (ii) by Executive Officer following Good Reason; provided, however, the term "Involuntary Termination" shall not include termination of Executive Officer’s employment due to Executive Officer’s death, Disability, or voluntary retirement.

(11) “ Potential Change in Control ” shall mean the earliest to occur of (i) the date on which the Corporation executes an agreement or letter of intent, where the consummation of the transaction described therein would result in the occurrence of a Change in Control, (ii) the date on which the Board of Directors approves a transaction or series of transactions, the consummation of which would result in a Change in Control, or (iii) the date on which a tender offer for the Corporation’s voting stock is publicly announced, the completion of which would result in a Change in Control; provided, however, that if such Potential Change in Control terminates by its terms, such transaction shall no longer constitute a Potential Change in Control.

(12) “ Potential Change in Control Date ” shall mean the date on which a Potential Change in Control occurs.

(13) “ Reference Salary ” shall mean the greater of (i) the annual rate of Executive Officer’s base salary from the Corporation or the employing subsidiary in effect immediately before the date of Executive Officer’s Involuntary Termination, or (ii) the annual rate of Executive Officer’s base salary from the Corporation or the employing subsidiary in effect immediately before the Change in Control Date.

(14) “ Termination Date ” shall be the date specified in the written notice of termination of Executive Officer’s employment given by either party in accordance with Section 3(b) of this Policy.

(b) Notice of Termination. During the Covered Period, in the event that the Corporation (including an employing subsidiary) or Executive Officer terminates Executive Officer’s employment with the Corporation or Employer, the party terminating employment shall give written notice of termination to the other party, specifying the Termination Date and the specific termination provision in this Section 3 that is relied upon, if any, and setting forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of Executive Officer’s employment under the provision so indicated. The Termination Date shall be determined as follows: (i) if Executive Officer’s employment is terminated for Disability, thirty (30) days after a Notice of Termination is given (provided that Executive Officer shall not have returned to the full-time performance of Executive Officer’s duties during such 30-day period); (ii) if Executive Officer’s employment is terminated by the Corporation in an Involuntary Termination, thirty days after the date the Notice of Termination is received by Executive Officer (provided that the Corporation may provide Officer with pay in lieu of notice, which shall be paid in a lump sum together with the payment described in Section 3 (c)(1) below); and (iii) if Executive Officer’s employment is terminated by the Corporation for Cause (as defined in this Section 3), the date specified in the Notice of Termination, provided, that the events or circumstances cited by the Board of Directors as constituting Cause are not cured by Executive Officer during any cure period that may be offered by the Board of Directors. The Date of Termination for a resignation of employment other than for Good Reason shall be the date set forth in the applicable notice, which shall be no earlier than ten (10) days after the date such notice is received by the Corporation, unless waived by the Corporation.

During the Covered Period, a notice of termination given by Executive Officer for Good Reason shall be given within 90 days after occurrence of the event on which Executive Officer bases his notice of termination and shall provide a Termination Date of thirty (30) days after the notice of termination is given to the Corporation (provided that the Corporation may provide Officer with pay in lieu of notice, which shall be paid in a lump sum together with the payment described in Section 3(c)(1) below).

(c) Corporation’s Obligations. If Executive Officer separates from service due to an Involuntary Termination within the Covered Period, then the Corporation shall provide Executive Officer the following benefits:

(1) The Corporation shall pay to the Executive Officer a lump sum in cash within thirty (30) days after the Executive Officer's separation from service :

a. the sum of (1) any earned but unpaid base salary through the Termination Date at the rate in effect at the time of the notice of termination to the extent not theretofore paid; (2) the Executive Officer's target bonus under the Short-Term Incentive Plan of the Corporation, an Affiliate, or a predecessor, for the fiscal year in which the Termination Date occurs (the "Target Bonus"); and (3) any accrued but unpaid vacation pay, in each case to the extent not theretofore paid; and

b. the amount equal to the product of (1) three and (2) the sum of (x) the Reference Salary and (y) the Target Bonus.

(2) The vesting of any benefits conditioned upon continued future employment shall accelerate in full upon the Executive Officer's separation from service and shall be delivered or paid in accordance with the terms thereof.

(3) Remedies. The Executive Officer shall be entitled to recover damages for late or nonpayment of amounts which the Corporation is obligated to pay hereunder. The Executive Officer shall also be entitled to seek specific performance of the Corporation's obligations and any other applicable equitable or injunctive relief.

(d) Adjustment for Excise Taxes. If any portion of the payments to the Executive Officer under this Section 3 or under any other plan, program, or arrangement maintained by the Corporation (a "Payment") would be subject to the excise tax levied under Section 4999 of the Internal Revenue Code ("Code"), or any interest or penalties are incurred by Executive Officer with respect to such excise tax (such excise tax together with such interest and penalties are referred to herein as the "Excise Tax"), then the Corporation shall make an additional payment to Executive Officer (a "Tax Restoration Payment") in an amount such that after payment by the Executive Officer of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Tax Restoration Payment, the Executive Officer retains an amount of the Tax Restoration Payment equal to the Excise Tax imposed upon the Payments. The payment of a Tax Restoration Payment under this Section 3 shall not be conditioned upon the Executive Officer's termination of employment.

All determinations and calculations required to be made under this Section 3(d) shall be made by Deloitte & Touche (the "Accounting Firm"), which shall provide its determination (the "Determination"), together with detailed supporting calculations regarding the amount of any Tax Restoration Payment and any other relevant matter, both to the Corporation and the Executive Officer within five (5) days of the termination of the Executive Officer's employment, if applicable, or such earlier time as is requested by the Corporation or the Executive Officer (if the Executive Officer reasonably believes that any of the Payments may be subject to Excise Tax). If the Accounting Firm determines that no Excise Tax is payable by the Executive Officer, it shall furnish the Executive Officer with a written statement that such Accounting Firm has concluded that no Excise Tax is payable (including the reasons therefor) and that the Executive

Officer has substantial authority not to report any Excise Tax on the Executive Officer's federal income tax return. If a Tax Restoration Payment is determined to be payable, it shall be paid to the Executive Officer within five (5) days after the Determination is delivered to the Corporation or the Executive Officer. Any determination by the Accounting Firm shall be binding upon the Corporation and the Executive Officer, absent manifest error.

As a result of uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Tax Restoration Payments not made by the Corporation should have been made (" Underpayment ") or that Tax Restoration Payments will have been made by the Corporation which should not have been made (" Overpayment "). In either such event, the Accounting Firm shall determine the amount of the Underpayment or Overpayment that has occurred. In the case of an Underpayment, the amount of such Underpayment shall be promptly paid by the Corporation to or for the benefit of the Executive Officer. In the case of an Overpayment, the Executive Officer shall, at the direction and expense of the Corporation, take such steps as are reasonably necessary (including the filing of returns and claims for refund), follow reasonable instructions from, and procedures established by, the Corporation, and otherwise reasonably cooperate with the Corporation to correct such Overpayment, provided, however, that (i) the Executive Officer shall in no event be obligated to return to the Corporation an amount greater than the net after-tax portion of the Overpayment that the Executive Officer has retained or has recovered as a refund from the applicable taxing authorities, and (ii) this provision shall be interpreted in a manner consistent with the intent of the Tax Restoration Payment paragraph above, which is to make the Executive Officer whole, on an after-tax basis, from the application of Excise Tax, it being understood that the correction of an Overpayment may result in the Executive Officer's repaying to the Corporation an amount that is less than the Overpayment.

All Tax Restoration Payments shall be paid no later than the calendar year next following the calendar year in which the Executive Officer remits the related taxes .

4. Administration. The Policy shall be administered by the Senior Human Resources Officer of the Corporation (" Administrator "), who shall have the authority to interpret the Policy and make and revise such rules as may be reasonably necessary to administer the Policy. The Administrator shall have the duty and responsibility of maintaining records, making the requisite calculations, securing Officer releases, and disbursing payments hereunder. The Administrator's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

5. No Mitigation. Payment of the amounts and benefits under Section 2(a) and Section 3 (except as otherwise provided in Section 2(a)(5)) shall not be subject to offset, counterclaim, recoupment, defense or other claim, right or action which the Corporation or an Employer may have and shall not be subject to a requirement that Officer mitigate or attempt to mitigate damages resulting from Officer's termination of employment.

6. Amendment and Termination. The Corporation, acting through its Nominating and Compensation Committee, reserves the right to amend or terminate the Policy at any time; provided, however, that any amendment which would reduce the aggregate level of benefits, or

terminate the Policy, shall not become effective prior to the third anniversary of the Corporation giving notice to Officers of such amendment or termination.

7. Successors. The Corporation will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business or assets of the Corporation expressly to assume and to agree to perform its obligations under this Policy in the same manner and to the same extent that the Corporation would be required to perform such obligations if no such succession had taken place; provided, however, that no such assumption shall relieve the Corporation of its obligations hereunder. As used herein, the "Corporation" shall mean the Corporation as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform its obligations by operation of law or otherwise.

This Policy shall inure to the benefit of and be binding upon the Officer (and Officer's personal representatives and heirs), Corporation and its successors and assigns, and any such successor or assignee shall be deemed substituted for the Corporation under the terms of this Policy for all purposes. As used herein, "successor" and "assignee" shall include any person, firm, corporation or other business entity which at any time, whether by purchase, merger or otherwise, directly or indirectly acquires the stock of the Corporation or to which the Corporation assigns this Policy by operation of law or otherwise. If Officer should die while any amount would still be payable to Officer hereunder if Officer had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with this Policy to Officer's devisee, legatee or other designee, or if there is no such designee, to Officer's estate.

8. Nonassignability of Benefits. The payments under this Policy or the right to receive future payments under this Policy may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for payments becomes bankrupt, the payments under the Policy of the person affected may be terminated by the Administrator who, in his or her sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that he or she deems appropriate.

9. Nonguarantee of Employment. Officers covered by the Policy are at-will employees, and nothing contained in this Policy shall be construed as a contract of employment between the Officer and the Corporation (or, where applicable, a subsidiary or affiliate of the Corporation), or as a right of the Officer to continued employment, or to remain as an Officer, or as a limitation on the right of the Corporation (or a subsidiary or affiliate of the Corporation) to discharge Officer at any time, with or without cause.

10. Benefits Unfunded and Unsecured. The payments under this Policy are unfunded, and the interest under this Policy of any Officer and such Officer's right to receive payments under this Policy shall be an unsecured claim against the general assets of the Corporation.

11. Applicable Law. All questions pertaining to the construction, validity, and effect of the Policy shall be determined in accordance with the laws of the United States and, to the extent not preempted by such laws, by the laws of the state of California.

12 . Arbitration. With the exception of any request for specific performance, injunctive or other equitable relief, any dispute or controversy of any kind arising out of or related to this Policy, Officer's employment with the Corporation (or with the employing subsidiary), the termination thereof or any claims for benefits shall be resolved exclusively by final and binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association then in effect. Provided, however, that in making their determination, the arbitrators shall be limited to accepting the position of the Officer or the position of the Corporation, as the case may be. The only claims not covered by this Section 12 are claims for benefits under workers' compensation or unemployment insurance laws; such claims will be resolved under those laws. The place of arbitration shall be San Francisco, California. Parties may be represented by legal counsel at the arbitration but must bear their own fees for such representation. The prevailing party in any dispute or controversy covered by this Section 12, or with respect to any request for specific performance, injunctive or other equitable relief, shall be entitled to recover, in addition to any other available remedies specified in this Policy, all litigation expenses and costs, including any arbitrator or administrative or filing fees and reasonable attorneys' fees. Such expenses, costs and fees, if payable to Officer, shall be paid within 60 days after they are incurred. Both the Officer and the Corporation specifically waive any right to a jury trial on any dispute or controversy covered by this Section 12. Judgment may be entered on the arbitrators' award in any court of competent jurisdiction.

13 . Reimbursements and In-Kind Benefits. Notwithstanding any other provision of this Policy, all reimbursements and in-kind benefits provided under this Policy shall be made or provided in accordance with the requirements of Code Section 409A, including, where applicable, the requirement that (i) the amount of expenses eligible for reimbursement and the provision of benefits in kind during a calendar year shall not affect the expenses eligible for reimbursement or the provision of in-kind benefits in any other calendar year; (ii) the reimbursement for an eligible expense will be made on or before the last day of the calendar year following the calendar year in which the expense is incurred (or by such earlier time set forth in this Policy); (iii) the right to reimbursement or right to in-kind benefit is not subject to liquidation or exchange for another benefit; and (iv) each reimbursement payment or provision of in-kind benefit shall be one of a series of separate payments (and each shall be construed as a separate identified payment) for purposes of Code Section 409A.

14 . Separate Payments. Each payment and benefit under this Policy shall be a "separate payment" for purposes of Code Section 409A.

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon
Senior Vice President, Human Resources

APPENDIX A

PARTICIPATING EMPLOYERS

PG&E Corporation
Pacific Gas and Electric Company
PG&E Corporation Support Services, Inc.

[PG&E CORPORATION LETTERHEAD]

**AMENDMENT TO PG&E CORPORATION
GOLDEN PARACHUTE RESTRICTION POLICY**

The PG&E Corporation Golden Parachute Restriction Policy (the "Policy") is hereby amended as follows:

1. If any Golden Parachute Benefits (as defined in the Policy) are reduced under the Policy, reduction shall be made in accordance with the following order of priority: (x) first, amounts payable in cash will be reduced in reverse chronological order such that the payment owed on the latest date following the date of the Senior Executive's employment termination date will be first reduced (with reductions made pro-rata in the event payments are owed at the same time) and (y) second, special benefits and perquisites will be reduced in reverse chronological order such that the benefits and perquisites owed on the latest date following the date of the Senior Executive's employment termination date will be first reduced (with reductions made pro-rata in the event benefits and perquisites are owed at the same time).

IN WITNESS WHEREOF, PG&E Corporation has caused this Plan to be executed by its Senior Vice President, Human Resources, at the direction of the Chief Executive Officer, on December 31, 2008.

PG&E CORPORATION

By: JOHN R. SIMON

John R. Simon

Senior Vice President - Human Resources

EXHIBIT 11

PG&E CORPORATION
COMPUTATION OF EARNINGS PER COMMON SHARE

	Year Ended December 31,		
	2008	2007	2006
(in millions, except per share amounts)			
Net Income	\$ 1,338	\$ 1,006	\$ 991
Less: distributed earnings to common shareholders	560	508	460
Undistributed earnings	778	498	531
Less: undistributed earnings from discontinued operations	154	-	-
Undistributed earnings from continuing operations	\$ 624	\$ 498	\$ 531
Common shareholder earnings			
Basic			
Distributed earnings to common shareholders	\$ 560	\$ 508	\$ 460
Undistributed earnings allocated to common shareholders – continuing operations	592	472	503
Undistributed earnings allocated to common shareholders – discontinued operations	146	-	-
Total common shareholders earnings, basic	\$ 1,298	\$ 980	\$ 963
Diluted			
Distributed earnings to common shareholders	\$ 560	\$ 508	\$ 460
Undistributed earnings allocated to common shareholders – continuing operations	593	473	504
Undistributed earnings allocated to common shareholders – discontinued operations	146	-	-
Total common shareholders earnings, diluted	\$ 1,299	\$ 981	\$ 964
Weighted average common shares outstanding, basic	357	351	346
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	376	370	365
Weighted average common shares outstanding, basic	357	351	346
Employee share-based compensation and accelerated share repurchases ⁽¹⁾	1	2	3
Weighted average common shares outstanding, diluted	358	353	349
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	377	372	368
Net earnings per common share, basic			
Distributed earnings, basic ⁽²⁾	\$ 1.57	\$ 1.45	\$ 1.33
Undistributed earnings – continuing operations, basic	1.66	1.34	1.45
Undistributed earnings – discontinued operations, basic	0.41	-	-
Total	\$ 3.64	\$ 2.79	\$ 2.78
Net earnings per common share, diluted			
Distributed earnings, diluted	\$ 1.56	\$ 1.44	\$ 1.32
Undistributed earnings – continuing operations, diluted	1.66	1.34	1.44
Undistributed earnings – discontinued operations, diluted	0.41	-	-
Total	\$ 3.63	\$ 2.78	\$ 2.76

⁽¹⁾ Includes approximately one million shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchase agreements (ASRs) for 2006. The remaining shares of approximately two million at December 31, 2006 relate to share-based compensation and are deemed to be outstanding under SFAS No. 128 for the purpose of calculating EPS. PG&E Corporation has no remaining obligation under these ASRs as of December 31, 2007.

⁽²⁾ “Distributed earnings, basic” differs from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual number of, shares outstanding.

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

	Year ended December 31,				
	2008	2007	2006	2005	2004
Earnings:					
Net income	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$ 3,982
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-
Income taxes provision	488	571	602	574	2,561
Net fixed charges	772	889	801	589	671
Total Earnings	\$ 2,459	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,214
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	794	\$ 834	\$ 770	\$ 573	\$ 682
Interest on capital leases	22	23	11	1	1
AFUDC debt	(44)	32	20	15	(12)
Earnings required to cover preferred stock dividends	-	-	-	-	-
Total Fixed Charges	\$ 772	\$ 889	\$ 801	\$ 589	\$ 671
Ratios of Earnings to Fixed Charges	3.19	2.79	2.98	3.56	10.75

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

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

	Year ended December 31,				
Earnings:	2008	2007	2006	2005	2004
Net income	\$ 1,199	\$ 1,024	\$ 985	\$ 934	\$ 3,982
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-
Income taxes provision	488	571	602	574	2,561
Net fixed charges	772	889	801	589	671
Total Earnings	\$ 2,459	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,214
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	\$ 794	834	770	\$ 573	\$ 682
Interest on capital leases	22	23	11	1	1
AFUDC debt	(44)	32	20	15	(12)
Earnings required to cover preferred stock dividends	-	-	-	-	-
Total Fixed Charges	772	889	801	589	671
Preferred Stock Dividends:					
Tax deductible dividends	9	9	12	12	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	7	8	3	13	34
Total Preferred Stock Dividends	16	17	15	25	43
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 788	\$ 906	\$ 816	\$ 614	\$ 714
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.12	2.74	2.93	3.42	10.10

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay dividends on the outstanding series of preferred stock. Fixed charges exclude interest on tax liabilities in accordance with FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes).

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SELECTED FINANCIAL DATA

	2008	2007	2006	2005	2004 ⁽¹⁾
(in millions, except per share amounts)					
PG&E Corporation⁽²⁾					
For the Year					
Operating revenues	\$ 14,628	\$ 13,237	\$ 12,539	\$ 11,703	\$ 11,080
Operating income	2,261	2,114	2,108	1,970	7,118
Income from continuing operations	1,184	1,006	991	904	3,820
Earnings per common share from continuing operations, basic	3.23	2.79	2.78	2.37	9.16
Earnings per common share from continuing operations, diluted ³	3.22	2.78	2.76	2.34	8.97
Dividends declared per common share ⁽³⁾	1.56	1.44	1.32	1.23	-
At Year-End					
Book value per common share ⁽⁴⁾	\$ 24.64	\$ 22.91	\$ 21.24	\$ 19.94	\$ 20.90
Common stock price per share	38.71	43.09	47.33	37.12	33.28
Total assets	40,860	36,632	34,803	34,074	34,540
Long-term debt (excluding current portion)	9,321	8,171	6,697	6,976	7,323
Rate reduction bonds (excluding current portion)	-	-	-	290	580
Energy recovery bonds (excluding current portion)	1,213	1,582	1,936	2,276	-
Preferred stock of subsidiary with mandatory redemption provisions	-	-	-	-	122
Pacific Gas and Electric Company					
For the Year					
Operating revenues	\$ 14,628	\$ 13,238	\$ 12,539	\$ 11,704	\$ 11,080
Operating income	2,266	2,125	2,115	1,970	7,144
Income available for common stock	1,185	1,010	971	918	3,961
At Year-End					
Total assets	\$ 40,537	\$ 36,310	\$ 34,371	\$ 33,783	\$ 34,302
Long-term debt (excluding current portion)	9,041	7,891	6,697	6,696	7,043
Rate reduction bonds (excluding current portion)	-	-	-	290	580
Energy recovery bonds (excluding current portion)	1,213	1,582	1,936	2,276	-
Preferred stock with mandatory redemption provisions	-	-	-	-	122

⁽¹⁾ Financial data reflects the recognition of regulatory assets provided under the December 19, 2003 settlement agreement entered into among PG&E Corporation, Pacific Gas and Electric Company, and the California Public Utilities Commission to resolve Pacific Gas and Electric Company's proceeding under Chapter 11 of the U.S. Bankruptcy Code. Pacific Gas and Electric Company's reorganization under Chapter 11 became effective on April 12, 2004.

⁽²⁾ Matters relating to discontinued operations are discussed in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in Note 6 of the Notes to the Consolidated Financial Statements.

⁽³⁾ The Board of Directors of PG&E Corporation declared a cash dividend of \$0.30 per share for the first three quarters of 2005. In the fourth quarter of 2005, the Board of Directors increased the quarterly cash dividend to \$0.33 per share. Beginning in the first quarter of 2007, the Board of Directors increased the quarterly cash dividend to \$0.36 per share. Beginning in the first quarter of 2008, the Board of Directors increased the quarterly cash dividend to \$0.39 per share. The Utility paid quarterly dividends on common stock held by PG&E Corporation and a wholly owned subsidiary aggregating to \$589 million in 2008 and \$547 million in 2007. See Note 7 of the Notes to the Consolidated Financial Statements.

⁽⁴⁾ Book value per common share includes the effect of participating securities. The dilutive effect of outstanding stock options and restricted stock are further disclosed in Note 9 of the Notes to the Consolidated Financial Statements.

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

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

The Utility served approximately 5.1 million electricity distribution customers and approximately 4.3 million natural gas distribution customers at December 31, 2008. The Utility had approximately \$40.5 billion in assets at December 31, 2008 and generated revenues of approximately \$14.6 billion in the 12 months ended December 31, 2008.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). The Utility generates revenues mainly through the sale and delivery of electricity and natural gas at rates set by the CPUC and the FERC. Rates are set to permit the Utility to recover its authorized "revenue requirements" from customers. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in Utility facilities ("rate base"). Changes in any individual revenue requirement affect customer rates and could affect the Utility's revenues.

This is a combined annual report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries, as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

Summary of Changes in Earnings per Common Share and Net Income for 2008

PG&E Corporation's diluted earnings per common share ("EPS") for 2008 was \$3.63 per share, compared to \$2.78 per share for 2007. PG&E Corporation's 2008 net income increased by approximately \$332 million, or 33%, to \$1,338 million, compared to 2007 net income of \$1,006 million. The increase in diluted EPS and net income in 2008 is primarily due to a settlement of federal tax audits of PG&E Corporation's consolidated tax returns for 2001 through 2004, which increased net income by \$257 million. (Approximately \$154 million of this amount has been reported as discontinued operations on PG&E Corporation's Consolidated Statements of Income because it relates to a former subsidiary of PG&E Corporation, National Energy & Gas Transmission, Inc. ("NEGT"), which PG&E Corporation disposed of in 2004.) The 2008 increase in diluted EPS and net income also includes approximately \$98 million representing the Utility's return on equity ("ROE") on higher authorized capital investments and approximately \$25 million in incentive earnings awarded by the CPUC in 2008 for the Utility's energy efficiency program performance in 2006 and 2007.

These increases in net income were partially offset by higher operating and maintenance expenses of approximately \$50 million due to storm-related outages, natural gas system maintenance activities, and the extended outage to replace the steam generators in one of the nuclear generating units at the Utility's Diablo Canyon nuclear generating facilities ("Diablo Canyon").

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation and the Utility's results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements, timely recover its authorized costs, and earn its authorized rate of return. A number of factors have had, or are expected to have, a significant impact on PG&E Corporation and the Utility's results of operations and financial condition, including:

- *The Outcome of Regulatory Proceedings and the Impact of Ratemaking Mechanisms.* Most of the Utility's revenue requirements are set based on its costs of service in proceedings such as the General Rate Case ("GRC") filed with the CPUC and transmission owner ("TO") rate cases filed with the FERC. Unlike the current GRC, which set revenue requirements for a four-year period (2007 through 2010), it is expected that the next GRC will set revenue requirements for the Utility's electric and natural gas distribution operations and electric generation operations for a three-year period (2011 through 2013). From time to time, the Utility also files separate applications requesting the CPUC or the FERC to authorize additional revenue requirements for specific capital expenditure projects, such as new power plants, gas or electric transmission facilities, installation of an advanced metering infrastructure, and reliability or system infrastructure improvements. The Utility's revenues will also be affected by incentive ratemaking, including the CPUC's customer energy efficiency shareholder incentive mechanism. (See "Regulatory Matters" below.) In addition, the CPUC has authorized the Utility to recover 100% of its reasonable electric fuel and energy procurement costs and has established a timely rate adjustment mechanism to recover such costs. As a result, the Utility's revenues and costs can be affected by volatility in the prices of natural gas and electricity. (See "Risk Management Activities" below.)
- *Capital Structure and Return on Common Equity.* The Utility's current CPUC-authorized capital structure includes a 52% common equity component. The CPUC has authorized the Utility to earn an ROE of 11.35% on the equity component of its electric and natural gas distribution and electric generation rate base. The Utility's capital structure is set until 2011, and its cost of capital components, including an 11.35% ROE, will only be changed before 2011 if the annual automatic adjustment mechanism established by the CPUC is triggered. If the 12-month October through September average yield for the Moody's Investors Service ("Moody's") utility bond index increases or decreases by more than 1% as compared to the applicable benchmark, the Utility can adjust its authorized cost of capital effective on January 1 of the following year. The 12-month October 2007 through September 2008 average yield of the Moody's utility bond index did not trigger a change in the Utility's authorized cost of capital for 2009. The Utility can also apply for an adjustment to either its capital structure or cost of capital at any time in the event of extraordinary circumstances.

- *The Ability of the Utility to Control Costs While Improving Operational Efficiency and Reliability*. The Utility's revenue requirements are generally set at a level to allow the Utility the opportunity to recover its basic forecasted operating expenses, as well as to earn an ROE and recover depreciation, tax, and interest expense associated with authorized capital expenditures. Differences in the amount or timing of forecasted and actual operating expenses and capital expenditures can affect the Utility's ability to earn its authorized rate of return and the amount of PG&E Corporation's net income available for shareholders. When capital expenditures are higher than authorized levels, the Utility incurs associated depreciation, property tax, and interest expense, but does not recover revenues to offset these expenses or earn an ROE, until the capital expenditures are added to rate base in future rate cases. Items that could cause higher expenses than provided for in the last GRC primarily relate to the Utility's efforts to maintain the aging infrastructure of its electric and natural gas systems, to improve the reliability and safety of its electric and natural gas systems, higher debt interest rates, and technology infrastructure and support. In addition, the Utility intends to accelerate the work associated with system-wide gas leak surveys and targets completing this work in a little more than a year. This is expected to result in additional costs. (See "Results of Operations" below.) The Utility continually seeks to achieve operational efficiencies and improve reliability while creating future sustainable cost-savings to offset these higher anticipated expenses. The Utility also seeks to make the amount and timing of its capital expenditures consistent with budgeted amounts and timing.
- *The Availability and Terms of Debt and Equity Financing*. The amount and timing of the Utility's future financing needs will depend on various factors, some of which include the conditions in the capital markets, the amount and timing of scheduled principal and interest payments on long-term debt, the amount and timing of planned capital expenditures, and the amount and timing of interest payments related to the remaining disputed claims that were made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11"). (See Note 15 of the Notes to the Consolidated Financial Statements.) The amount of the Utility's short-term financing will vary depending on the level of operating cash flows, seasonal demand for electricity and natural gas, volatility in electricity and natural gas prices, and collateral requirements related to price risk management activity, among other factors. The Utility has continued to have access to the capital markets despite the recent financial turmoil and economic downturn, although interest rates on the Utility's short-term and long-term debt have increased. For example, the Utility's \$600 million principal amount of 10-year senior notes, issued on October 21, 2008, bears interest at 8.25% compared to the Utility's \$700 million principal amount of 10-year senior notes, issued in December 2007 and March 3, 2008 that bear interest at 5.625%. In addition, the Utility's commercial paper issuance rate reached a high of 7.3% on September 30, 2008 and a low of 1.2% as of December 26, 2008. In order to maintain the Utility's CPUC-authorized capital structure, PG&E Corporation will be required to contribute equity to the Utility. The timing and amount of these future equity contributions will affect the timing and amount of any future equity or debt issuances by PG&E Corporation. (See "Liquidity and Financial Resources" below.)

In addition to the key factors discussed above, PG&E Corporation and the Utility's future results of operations and financial condition are subject to the risk factors. (See "Risk Factors" below.)

FORWARD-LOOKING STATEMENTS

This combined annual report and the letter to shareholders that accompanies it, contain forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, estimated future cash flows and the level of future equity or debt issuances, and are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential," and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to manage capital expenditures and its operating and maintenance expenses within authorized levels;
- the outcome of pending and future regulatory proceedings and whether the Utility is able to timely recover its costs through rates;
- the adequacy and price of electricity and natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the electricity and natural gas markets, including the ability of the Utility and its counterparties to post or return collateral;
- the effect of weather, storms, earthquakes, fires, floods, disease, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards on the Utility's facilities and operations, its customers, and third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas businesses;
- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology, including the development of alternative energy sources, or other reasons;
- operating performance of Diablo Canyon, the availability of nuclear fuel, the occurrence of unplanned outages at Diablo Canyon, or the temporary or permanent cessation of operations at Diablo Canyon;
- whether the Utility can maintain the cost savings it has recognized from operating efficiencies it has achieved and identify and successfully implement additional sustainable cost-saving measures;

- whether the Utility incurs substantial expense to improve the safety and reliability of its electric and natural gas systems;
- whether the Utility achieves the CPUC’s energy efficiency targets and recognizes any incentives the Utility may earn in a timely manner;
- the impact of changes in federal or state laws, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- the impact of changing wholesale electric or gas market rules, including new rules of the California Independent System Operator (“CAISO”) to restructure the California wholesale electricity market;
- how the CPUC administers the conditions imposed on PG&E Corporation when it became the Utility’s holding company;
- the extent to which PG&E Corporation or the Utility incurs costs and liabilities in connection with litigation that are not recoverable through rates, from insurance, or from other third parties;
- the ability of PG&E Corporation, the Utility, and counterparties, to access capital markets and other sources of credit in a timely manner on acceptable terms, especially given the recent deteriorating conditions in the economy and financial markets;
- the impact of environmental laws and regulations and the costs of compliance and remediation;
- the effect of municipalization, direct access, community choice aggregation, or other forms of bypass; and
- the impact of changes in federal or state tax laws, policies, or regulations.

For more information about the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation and the Utility’s future financial condition and results of operations see the discussion in the section entitled “Risk Factors” below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events or otherwise.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Income for 2008, 2007, and 2006:

	Year ended December 31,		
	2008	2007	2006
(in millions)			
Utility			
Electric operating revenues	\$ 10,738	\$ 9,481	\$ 8,752
Natural gas operating revenues	3,890	3,757	3,787
Total operating revenues	14,628	13,238	12,539
Cost of electricity	4,425	3,437	2,922
Cost of natural gas	2,090	2,035	2,097
Operating and maintenance	4,197	3,872	3,697
Depreciation, amortization, and decommissioning	1,650	1,769	1,708
Total operating expenses	12,362	11,113	10,424
Operating income	2,266	2,125	2,115
Interest income	91	150	175
Interest expense	(698)	(732)	(710)
Other income (expense), net ⁽¹⁾	14	38	(7)
Income before income taxes	1,673	1,581	1,573
Income tax provision	488	571	602
Income available for common stock	\$ 1,185	\$ 1,010	\$ 971
PG&E Corporation, Eliminations, and Other ⁽²⁾			
Operating revenues	\$ -	\$ (1)	\$ -
Operating expenses	5	10	7
Operating loss	(5)	(11)	(7)
Interest income	3	14	13
Interest expense	(30)	(30)	(28)
Other expense, net	(32)	(9)	(6)
Loss before income taxes	(64)	(36)	(28)
Income tax benefit	(63)	(32)	(48)
Income (loss) from continuing operations	(1)	(4)	20
Discontinued operations ⁽³⁾	154	-	-
Net income (loss)	\$ 153	\$ (4)	\$ 20
Consolidated Total			
Operating revenues	\$ 14,628	\$ 13,237	\$ 12,539
Operating expenses	12,367	11,123	10,431
Operating income	2,261	2,114	2,108
Interest income	94	164	188
Interest expense	(728)	(762)	(738)
Other income (expense), net ⁽¹⁾	(18)	29	(13)
Income before income taxes	1,609	1,545	1,545
Income tax provision	425	539	554
Income from continuing operations	1,184	1,006	991
Discontinued operations ⁽³⁾	154	-	-
Net income	\$ 1,338	\$ 1,006	\$ 991

⁽¹⁾ Includes preferred stock dividend requirement as other expense.

⁽²⁾ PG&E Corporation eliminates all intercompany transactions in consolidation.

⁽³⁾ Discontinued operations reflect items related to PG&E Corporation's former subsidiary NEGT. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion.

Utility

In the Utility's last GRC, the CPUC authorized the Utility's revenue requirements for 2007 through 2010 for its basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. Effective January 1, 2007, the CPUC authorized the Utility to collect annual revenue requirements of approximately \$2.9 billion for electricity distribution, approximately \$1.0 billion for natural gas distribution, and approximately \$1.0 billion for electricity generation operations. The CPUC also authorized annual increases (known as attrition adjustments) to authorized revenues of \$125 million in 2008, 2009, and 2010, to help avoid a reduction in earnings in years between GRCs due to inflation, increases in invested capital, and other similar items. In addition, the CPUC authorized a one-time additional adjustment of \$35 million in 2009 for the cost of a second refueling outage at the Utility's Diablo Canyon nuclear power plant. The Utility's next GRC will be held in 2010 to establish revenue requirements beginning in 2011. The Utility expects to submit a draft of its GRC application and revenue requirement request to the CPUC staff in July or August of 2009.

Revenue requirements by the CPUC are independent, or "decoupled," from the volume of sales, which eliminates volatility in the amount of revenues earned by the Utility due to fluctuations in customer demand. As a result, lower customer demand caused by the economic downturn has not and is not expected to have a material adverse impact on the Utility's results of operations or financial condition. The Utility uses revenue or sales regulatory balancing accounts to accumulate differences between revenues and the Utility's revenue requirements authorized by the CPUC. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The CPUC also conducts a proceeding to determine the Utility's authorized capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) and the authorized rate of return (including an ROE) that the Utility may earn on the components of capital structure used to finance its electricity and natural gas distribution and electricity generation assets. For 2008 through 2010, the CPUC has authorized a capital structure that includes a 52% equity component. For 2009, the CPUC has authorized an 11.35% ROE for the Utility. The Utility's rates of return will remain at current levels through 2010, unless the CPUC's annual adjustment mechanism is triggered. The CPUC will review the Utility's capital structure and cost of capital again for possible reset beginning in 2011.

The CPUC also authorizes the Utility's revenue requirements and associated rates for the Utility's natural gas transmission and storage services. In September 2007, the CPUC approved a multi-party settlement agreement, known as the Gas Accord IV, to establish the Utility's natural gas transmission and storage rates and associated revenue requirements for 2008 through 2010. The Gas Accord IV establishes a 2008 natural gas transmission and storage revenue requirement of \$446 million, with slight increases in 2009 and 2010. Although most of the Utility's natural gas revenues are collected through balancing accounts, most of the Utility's transportation service-only revenue is based on actual volumes of natural gas sold and therefore is subject to volumetric risk.

The Utility is also authorized to collect revenue requirements from customers to fund public purpose, demand response, and energy efficiency programs, including the California Solar Initiative program and the Self-Generation Incentive program. In addition, the Utility is authorized to collect revenue requirements to recover its capital costs for projects such as new Utility-owned generation resource facilities and the installation of advanced meters for its electric and gas customers. Finally, incentive ratemaking mechanisms allow rates to be adjusted to reflect incentive awards earned by the Utility, or obligations incurred by the Utility, to the extent certain benchmarks or goals are or are not met.

The FERC sets the Utility's rates for electric transmission services. The primary FERC ratemaking proceeding to determine the amount of revenue requirements that the Utility can recover for its electric transmission costs is the TO rate case. The Utility is typically able to set the schedule for its TO rate cases and, if accepted by the FERC, to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process. The Utility's recovery of its FERC-authorized electric transmission revenue requirements can vary with the volume of electricity sales. As a result, lower customer demand caused by the economic downturn could affect the Utility's results of operations or financial condition. (See "Regulatory Matters – Electric Transmission Owner Rate Cases" below.)

The Utility's rates reflect the revenue requirement components authorized by the CPUC and the FERC. In annual true-up proceedings, the Utility requests the CPUC to authorize an adjustment to electric and gas rates to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) implement various other electricity and gas revenue requirement changes authorized by the CPUC and the FERC. Generally, these rate changes become effective on the first day of the following year. Balances in all CPUC-authorized accounts are subject to review, verification audit, and adjustment, if necessary, by the CPUC.

The following presents the Utility's operating results for 2008, 2007, and 2006.

Electric Operating Revenues

The Utility provides electricity to residential, industrial, agricultural, and small and large commercial customers through its own generation facilities and through power purchase agreements with third parties. In addition, the Utility relies on electricity provided under long-term contracts entered into by the California Department of Water Resources ("DWR") to meet a material portion of the Utility's customers' demand ("load"). The Utility's electric operating revenues consist of amounts charged to customers for electricity generation and procurement and for electric transmission and distribution services, as well as amounts charged to customers to recover the costs of public purpose programs, energy efficiency programs, and demand side management.

The following table provides a summary of the Utility's electric operating revenues:

	2008	2007	2006
(in millions)			
Electric operating revenue	\$ 12,063	\$ 11,710	\$ 10,871
DWR pass-through revenue ⁽¹⁾	(1,325)	(2,229)	(2,119)
Utility electric operating revenue	<u>\$ 10,738</u>	<u>\$ 9,481</u>	<u>\$ 8,752</u>

Utility electricity sales (in millions of kWh) ⁽²⁾	74,783	64,986	64,725

⁽¹⁾ These are revenues collected on behalf of the DWR for electricity allocated to the Utility's customers under contracts between the DWR and power suppliers, and are not included in the Utility's Consolidated Statements of Income.

⁽²⁾ These volumes exclude electricity provided by DWR.

The Utility's electric operating revenues increased by approximately \$1,257 million, or approximately 13%, in 2008 compared to 2007 mainly due to the following factors:

- Electricity procurement costs passed through to customers increased by approximately \$976 million, primarily due to an increase in the volume of power purchased by the Utility following the DWR's termination of a power purchase contract in December 2007 and during the extended scheduled outage at Diablo Canyon in 2008. (See "Cost of Electricity" below.)
- Electric operating revenues to fund public purpose and energy efficiency programs increased by approximately \$266 million, primarily due to an increase in expenses for these programs. (See "Operating and Maintenance" below.)
- Base revenue requirements increased by approximately \$103 million, as a result of attrition adjustments as authorized in the 2007 GRC.
- Electric transmission revenues increased by approximately \$56 million, primarily due to an increase in rates as authorized in the current TO rate case.
- Electric operating revenues increased by approximately \$35 million, the portion of the incentive award approved by the CPUC in December 2008 that is attributable to the Utility's 2006 and 2007 electricity energy efficiency programs.
- Other electric operating revenues increased by approximately \$119 million, primarily due to increases in revenue requirements to recover costs related to the Diablo Canyon steam generator replacement project and revenue requirements to fund the SmartMeter™ advanced metering project. (See "Capital Expenditures" below.)

These increases were partially offset by a decrease of approximately \$276 million representing the amount of revenue collected during the comparable periods in 2007 for payment of principal and interest on the rate reduction bonds ("RRBs") that matured in December 2007 and approximately \$22 million, representing a reduction in the amount of revenue collected for payment of the energy recovery bonds ("ERBs") due to their declining balance.

The Utility's electric operating revenues increased by approximately \$729 million, or approximately 8%, in 2007 compared to 2006 mainly due to the following factors:

- Electricity procurement costs, which are passed through to customers, increased by approximately \$742 million. (See "Cost of Electricity" below.)
- The 2007 GRC increased 2007 base revenue requirements by approximately \$231 million.
- Revenues from public purpose programs, including the California Solar Initiative program, increased by approximately \$141 million. (See Note 3 of the Notes to the Consolidated Financial Statements.)
- Electric transmission revenues increased by approximately \$74 million, including an increase in revenues as authorized in the TO rate case.

These increases were partially offset by the following:

- Transmission revenues decreased by approximately \$200 million primarily due to a decrease in revenues received under the Utility's reliability must run ("RMR") agreements with the CAISO. During 2006, the CPUC adopted rules to implement state law requirements for California investor-owned utilities to meet resource adequacy requirements, including rules to address local transmission system reliability issues. As the utilities fulfill their responsibilities to meet these requirements, the number of RMR agreements with the CAISO and the associated revenues and costs will decline. (See "Cost of Electricity" below.)
- Revenues in 2006 included approximately \$136 million for recovery of scheduling coordinator costs the Utility incurred from April 1998 through December 2005, as ordered by the FERC. No similar amount was recognized in 2007.
- Revenues in 2006 included approximately \$65 million for recovery of net interest related to Disputed Claims for the period between the effective date of the Utility's plan of reorganization under Chapter 11 in April 2004 and the first issuance of the ERBs in February 2005, and for certain energy supplier refund litigation costs upon completion of the CPUC's 2005 Annual Electric True-up verification audit. No similar amount was recognized in 2007.
- Other electric operating revenues decreased by approximately \$58 million, reflecting a pension revenue requirement that was recovered in 2006 but not in 2007.

The Utility's electric operating revenues for 2009 and 2010 are expected to increase as authorized by the CPUC in the 2007 GRC. The Utility's electric operating revenues for future years are also expected to increase as authorized by the FERC in the TO rate cases. In addition, the Utility expects to continue to collect revenue requirements related to CPUC-approved capital expenditures outside the GRC, including capital expenditures for the new Utility-owned generation projects and the SmartMeterTM advanced metering project. Revenues would also increase to the extent the CPUC approves the Utility's proposal for other capital projects. (See "Capital Expenditures" below.) Revenue requirements associated with new or expanded public purpose, energy efficiency, and demand response programs will also result in increased electric operating revenues. Future electric operating revenues are impacted by changes in the Utility's electricity procurement costs as discussed under "Cost of Electricity" below. Finally, the Utility may recognize additional incentive revenues to the extent it achieves the CPUC's energy efficiency goals.

Cost of Electricity

The Utility's cost of electricity includes the cost of purchased power and the cost of fuel used by its generation facilities or supplied to other facilities under tolling agreements. The Utility's cost of electricity also includes realized gains and losses on price risk management activities. (See Note 11 and 12 of the Notes to the Consolidated Financial Statements for further information.) The cost of electricity excludes non-fuel costs associated with the Utility's own generation facilities, which are included in Operating and maintenance expense in the Consolidated Statements of Income. The Utility's cost of purchased power and the cost of fuel used in Utility-owned generation are passed through to customers.

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio in the most cost-effective way. This requirement, in certain cases, requires the Utility to schedule more electricity than is necessary to meet its load and sell the excess electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. The Utility's net proceeds from the sale of surplus electricity are recorded as a reduction to the cost of electricity.

The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power:

	2008	2007	2006
(in millions)			
Cost of purchased power	\$ 4,516	\$ 3,443	\$ 3,114
Proceeds from surplus sales allocated to the Utility	(255)	(155)	(343)
Fuel used in own generation	164	149	151
Total cost of electricity	\$ 4,425	\$ 3,437	\$ 2,922
Average cost of purchased power per kWh	\$ 0.088	\$ 0.089	\$ 0.084
Total purchased power (in millions of kWh)	51,100	38,828	36,913

The Utility's total cost of electricity increased by approximately \$988 million, or 29%, in 2008 compared to 2007. This increase was primarily driven by increases in the total volume of purchased power of 12,272 million kilowatt-hours ("kWh"), or 32%. Following the DWR's termination of its power purchase agreement with Calpine Corporation in December 2007, the volume of power provided by the DWR to the Utility's customers decreased by 8,784 million kWh. As a result, the Utility was required to increase its purchases of power from third parties to meet customer load. In addition, the Utility increased the volume of power it purchased in 2008 from third parties during the scheduled extended outage at Diablo Canyon Unit 2 to replace the four steam generators. The extended outage lasted from February through mid-April 2008, in comparison to the planned refueling outage of Diablo Canyon Unit 1 that occurred entirely in May 2007. (See "Capital Expenditures" below.) Increases in market prices during the first half of 2008 were entirely offset by a decrease in market prices during the second half of 2008 and hedging activity.

The Utility's total cost of electricity increased by approximately \$515 million, or 18%, in 2007 compared to 2006. This increase was primarily driven by a 6% increase in the average cost of purchased power. The average cost of purchased power increased \$0.005 per kWh from 2006 to 2007 primarily due to higher energy payments made to qualifying facilities after their five-year fixed price contracts expired during the summer of 2006. In addition, the Utility increased the volume of its third party power purchases primarily due to a reduction in the availability of lower-cost hydroelectric power resulting from less than average precipitation during 2007 as compared to 2006. These increases were partially offset by a decrease in charges imposed by the CAISO.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the level of hydroelectric and nuclear power that the Utility produces, the cost of procuring more renewable energy, changes in customer demand, and the amount and timing of power purchases needed to replace power previously supplied under the DWR contracts as those contracts expire or are terminated, novated, or renegotiated. (See Note 17 of the Notes to the Consolidated Financial Statements.) The Utility will incur higher costs to purchase power during the extended refueling outage that began at Diablo Canyon Unit 1 in January 2009 to replace the steam generators. (See "Capital Expenditures" below.) In addition, the output from the Utility's hydroelectric generation facilities is dependent on levels of precipitation and could impact the volume of purchased power. Volatility in natural gas prices will also impact the Utility's cost of electricity in 2009 and future years.

The Utility's future cost of electricity also may be affected by federal or state legislation or rules which may be adopted to regulate the emissions of greenhouse gases from the Utility's electricity generating facilities or the generating facilities from which the Utility procures electricity. In particular, costs are likely to increase in the future when California's statewide greenhouse gas emissions reduction law is implemented. (See "Risk Factors" below).

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services. The Utility's transportation services are provided by a transmission system and a distribution system. The transmission system transports gas throughout California for delivery to the Utility's distribution system which, in turn, delivers natural gas to end-use customers. The transmission system also delivers natural gas to large end-use customers who are connected directly to the transmission system. In addition, the Utility delivers natural gas to off-system markets, primarily in southern California.

The Utility's natural gas customers consist of two categories: residential and smaller commercial customers known as "core" customers, and industrial and larger commercial customers known as "non-core" 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 from either the Utility or alternate energy service providers. The Utility does not procure natural gas for non-core customers. When the Utility provides both transportation and natural gas supply, the Utility refers to the combined service as bundled natural gas service. In 2008, core customers represented over 99% of the Utility's total customers and approximately 37% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 63% of its total natural gas deliveries.

The Utility's natural gas operating revenues include bundled natural gas revenues and transportation service-only revenues. Although the Utility's bundled natural gas revenues are collected through balancing accounts, most of the Utility's transportation service-only revenues are based on actual volumes sold and therefore are subject to volumetric risk. (Most of the Utility's intrastate natural gas transmission capacity has not been sold under long-term contracts that provide for recovery of all fixed costs through the collection of fixed reservation charges.) As a result, the Utility's natural gas operating revenues may fluctuate based on the volume of gas transported. (See the "Natural Gas Transportation and Storage" section in "Risk Management Activities" below.)

The following table provides a summary of the Utility's natural gas operating revenues:

	2008	2007	2006
(in millions)			
Bundled natural gas revenues	\$ 3,557	\$ 3,417	\$ 3,472
Transportation service-only revenues	333	340	315
Total natural gas operating revenues	\$ 3,890	\$ 3,757	\$ 3,787
Average bundled revenue per Mcf ⁽¹⁾ of natural gas sold	\$ 13.52	\$ 12.94	\$ 12.91
Total bundled natural gas sales (in millions of Mcf)	263	264	269

⁽¹⁾ One thousand cubic feet

The Utility's natural gas operating revenues increased by approximately \$133 million, or 4%, in 2008 compared to 2007. The increase in natural gas operating revenues primarily reflects an overall increase in the cost of natural gas of approximately \$55 million (see "Cost of Natural Gas" below), an increase in base revenue requirements as a result of attrition adjustments authorized in the 2007 GRC of approximately \$22 million, an increase in natural gas revenue requirements to fund the SmartMeter TM advanced metering project of approximately \$25 million, and an increase of \$24 million in natural gas revenues to fund energy efficiency public purpose program. The increase in natural gas operating revenues also includes \$7 million, the portion of the incentive award approved by the CPUC in December 2008 that is attributable to the Utility's 2006 and 2007 natural gas energy efficiency programs.

The Utility's natural gas operating revenues decreased by approximately \$30 million, or less than one percent, in 2007 compared to 2006. This was primarily due to a decrease in the cost of natural gas, which is passed through to customers. This decrease was partially offset by the increased base revenue requirements authorized in the 2007 GRC and an increase in revenue requirements relating to the SmartMeter TM project.

Future natural gas operating revenues will be impacted by changes in the cost of natural gas, the Utility's gas transportation rates, natural gas throughput volume, and other factors. For 2008 through 2010, the Gas Accord IV settlement agreement provides for an overall modest increase in the revenue requirements and rates for the Utility's gas transmission and storage services. In addition, the Utility's natural gas operating revenues for distribution are expected to increase through 2010 as a result of revenue requirement increases authorized by the CPUC in the 2007 GRC. Finally, the Utility may recognize incentive revenues to the extent it achieves the CPUC's energy efficiency goals.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas and transportation costs on interstate pipelines and intrastate pipelines, but excludes the transportation costs for non-core customers, which are included in Operating and Maintenance expense in the Consolidated Statements of Income. The Utility's cost of gas also includes realized gains and losses on price risk management activities. (See Note 11 and 12 of the Notes to the Consolidated Financial Statements for further information.) The Utility's cost of gas is passed through to customers.

The following table provides a summary of the Utility's cost of natural gas:

	2008	2007	2006
(in millions)			
Cost of natural gas sold	\$ 1,955	\$ 1,859	\$ 1,958
Cost of natural gas transportation	135	176	139
Total cost of natural gas	\$ 2,090	\$ 2,035	\$ 2,097
Average cost per Mcf of natural gas sold	\$ 7.43	\$ 7.04	\$ 7.28
Total natural gas sold (in millions of Mcf)	263	264	269

The Utility's total cost of natural gas increased by approximately \$55 million, or 3%, in 2008 compared to 2007, primarily due to increases in the average market price of natural gas purchased. The increase was partially offset by an approximately \$23 million refund the Utility received as part of a settlement with TransCanada's Gas Transmission Northwest Corporation for 2007 gas transmission capacity rates.

The Utility's total cost of natural gas decreased by approximately \$62 million, or 3%, in 2007 compared to 2006, primarily due to a decrease in the average market price of natural gas purchased of approximately \$0.24 per Mcf, or 3%. Average market prices were significantly higher in the beginning of 2006 as damages to production facilities caused by severe weather reduced natural gas supply. In addition, the price of natural gas declined due to a relatively mild hurricane season in 2007 as compared to industry forecasts, resulting in no material supply disruptions, and a relatively large amount of natural gas in storage across the nation.

The Utility's future cost of natural gas will be impacted by the market price of natural gas, and changes in customer demand. In addition, the Utility's future cost of gas also may be affected by federal or state legislation or rules to regulate the emissions of greenhouse gases from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses.

The Utility's operating and maintenance expenses increased by approximately \$325 million, or 8%, in 2008 compared to 2007. Expenses increased mainly due to the following factors:

- Public purpose program and customer energy efficiency incentive program expenses increased by approximately \$290 million primarily due to increased customer participation and increased marketing of new and existing programs, including the California Solar Initiative program and the Self-Generation Incentive Program. Of these changes, approximately \$266 million were recovered in electric operating revenues and \$24 million were recovered in natural gas operating revenues. Expenses related to public purpose programs and energy efficiency programs are generally fully recoverable and differences between costs and revenues in a particular period are due to timing differences.
- Employee benefit costs increased by approximately \$59 million, primarily reflecting unrealized losses in the long-term disability plan trust due to the decline in the market value of trust investments as financial markets deteriorated in the second half of 2008.
- Costs increased by approximately \$38 million for the repair and restoration of electric distribution systems and to respond to customer inquiries following the January 2008 winter storm. Of the approximately \$38 million in costs, the CPUC has authorized the Utility to recover approximately \$8 million from customers. There was no similar storm in the same period in 2007.
- Labor costs increased by approximately \$39 million to conduct expanded natural gas leak surveys in parts of the Utility's service territory and to make related repairs in an effort to improve operating and maintenance processes in the Utility's natural gas system.
- Maintenance costs increased by approximately \$10 million due to the longer duration of the planned outage of Diablo Canyon Unit 2 in 2008 compared to the Diablo Canyon Unit 1 outage in 2007.

These increases were partially offset by the following factors:

- Cost reductions of approximately \$60 million, reflecting reductions in labor, postage, consulting, advertising, and other costs.
- Costs related to injuries and damages decreased by approximately \$16 million, as compared to 2007 when the Utility increased its reserves for such matters.
- Costs related to software maintenance contracts decreased by \$10 million.
- Costs decreased by approximately \$12 million as compared to 2007 when the CPUC ordered the Utility to make customer refunds related to billing practices.
- Costs decreased by approximately \$13 million as compared to 2007 when the Utility increased the liability related to compensation for employees' missed meals.

During 2007, the Utility's operating and maintenance expenses increased by approximately \$175 million, or 5%, compared to 2006, mainly due to the following factors:

- Payments for customer assistance and public purpose programs, such as the California Solar Initiative program, increased by approximately \$99 million primarily due to increased customer participation in these programs.
- The Utility's distribution expenses increased by approximately \$40 million primarily due to service costs related to the creation of new dispatch and scheduling stations and vegetation management in the Utility's service territory.
- Billing and collection costs increased by approximately \$33 million.
- Labor costs increased by approximately \$33 million primarily due to higher employee headcount and increased base salaries and incentive compensation.
- Costs of outside consulting services and contracts primarily related to information systems increased by approximately \$22 million.
- Approximately \$22 million was accrued for missed meal payments to certain Utility employees covered under collective bargaining agreements.
- Workers' compensation expense increased by approximately \$20 million due to an increase in the Utility's accrual for its workers' compensation obligation (caused by a decrease to the applicable discount rate used to calculate the obligation) and higher than expected workers' compensation claims.
- Property taxes increased by approximately \$12 million due to electric plant growth, tax rate increases, and increases in assessed values in 2007.
- In 2006, the Utility reduced its accrual for long-term disability benefits by approximately \$11 million reflecting changes in sick leave eligibility rules, but there was no similar adjustment in 2007.

These increases were offset by the following factors:

- Pension expense decreased by approximately \$57 million consistent with the annual pension contribution, as approved by the CPUC in June 2006.
- Severance costs in 2007 were approximately \$30 million lower than in 2006.
- In 2006, the Utility increased its environmental remediation accrual by approximately \$30 million due to changes in the California Regional Water Quality Control Board's imposed remediation levels, but there was no similar adjustment in 2007.

Operating and maintenance expenses are influenced by wage inflation; benefits; property taxes; the timing and length of Diablo Canyon refueling outages; storms, wild land fires, and other events causing outages and damages in the Utility's service territory; environmental remediation costs; legal costs; material costs; and various other administrative and general expenses. In addition, the Utility expects to incur higher labor costs under its recently renegotiated collective bargaining agreements. The Utility anticipates that it will incur higher costs in the future to operate and maintain its aging infrastructure and to improve operating and maintenance processes used in its natural gas system. (See "Risk Factors" below.) In particular, the Utility intends to accelerate the work associated with system-wide gas leak surveys and targets completing this work in little more than a year. In general, the Utility completes a survey of its entire gas distribution system every five years by surveying 20% of its system each year. The Utility forecasts it will spend up to \$100 million more in 2009 to perform the gas leak surveys and associated remedial work on an accelerated schedule. The Utility also expects that it will incur higher expenses in future periods to obtain or comply with permitting requirements, including costs associated with renewed FERC licenses for the Utility's hydroelectric generation facilities. To help offset these increased costs, the Utility intends to continue its efforts to identify and implement initiatives to achieve operational efficiencies and to create future sustainable cost-savings.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses decreased by approximately \$119 million, or 7% in 2008 compared to 2007, mainly due to decreases in amortization expense of approximately \$261 million related to the RRB regulatory asset. The RRB regulatory asset was fully recovered through rates when the RRBs matured in December 2007; therefore no amortization has been recorded in 2008. These decreases were partially offset by increases to depreciation expense of approximately \$142 million primarily due to capital additions and depreciation rate changes as authorized in the 2007 GRC and the current TO rate case.

The Utility's depreciation, amortization, and decommissioning expenses increased by approximately \$61 million, or 4%, in 2007 compared to 2006, mainly due to an approximately \$121 million increase in depreciation expense as a result of depreciation rate changes and capital additions in 2007 authorized by the 2007 GRC decision. This was partially offset by the following factors:

- The Utility recorded lower decommissioning expense of approximately \$53 million as a result of the 2007 GRC decision to refund over-collections of decommissioning expense to customers.
- Other depreciation, amortization, and decommissioning expenses, including amortization of the ERB regulatory asset, decreased by \$7 million.

The Utility's depreciation, amortization, and decommissioning expenses in subsequent years are expected to increase as a result of an overall increase in capital expenditures and implementation of depreciation rates authorized by the 2007 GRC decision and future TO rate cases.

Interest Income

The Utility's interest income decreased by approximately \$59 million, or 39%, in 2008 as compared to 2007 when the Utility received approximately \$16 million in interest income on a federal tax refund. In addition, there was a decrease of \$37 million in interest income, primarily due to lower interest rates earned on funds held in escrow related to disputed claims and a lower escrow balance reflecting settlements of disputed claims. (See Note 15 of the Notes to the Consolidated Financial Statements.) There was an additional decrease of approximately \$6 million in other interest income.

The Utility's interest income decreased by approximately \$25 million, or 14%, in 2007 compared to 2006. In 2006, the FERC approved the Utility's recovery of scheduling coordinator costs it had previously incurred, including interest of approximately \$47 million. No similar amount was recognized in 2007. This decrease was partially offset by the receipt of approximately \$16 million in 2007 related to the settlement of refund claims made against electricity suppliers for overcharges incurred during the 2000-2001 California energy crisis. (See Note 15 of the Notes to the Consolidated Financial Statements.) In addition, other interest income, including interest income associated with certain balancing accounts, increased by approximately \$6 million.

The Utility's interest income in 2009 and future periods will be primarily affected by changes in the balance held in escrow related to disputed claims and changes in interest rate levels.

Interest Expense

The Utility's interest expense decreased by approximately \$34 million, or 5%, in 2008 as compared to 2007. Interest expense decreased primarily due to the following factors:

- Interest expense decreased by approximately \$29 million primarily due to lower FERC interest rates accrued on the liability for disputed claims.
- Interest expense decreased by approximately \$26 million due to the reduction in the outstanding balance of ERBs and the maturity of the RRBs in December 2007.

- Interest expense on pollution control bonds decreased by approximately \$20 million due to the repurchase of auction rate pollution control bonds in March and April 2008. The Utility partially refunded these bonds in September and October 2008. Additionally, interest expense decreased due to lower interest rates on outstanding variable rate pollution control bonds.
- Interest expense decreased by approximately \$24 million primarily due to lower interest rates affecting various balancing accounts.
- Other interest expense decreased by approximately \$14 million primarily due to a lower balance of borrowings outstanding under the Utility's \$2 billion revolving credit facility and lower commercial paper interest rates.

These decreases were partially offset by additional interest expense of approximately \$79 million in 2008 primarily related to \$1.8 billion in senior notes that were issued in March, October, and November 2008.

In 2007, the Utility's interest expense increased by approximately \$22 million, or 3%, compared to 2006, including approximately \$19 million of higher interest expense related to disputed claims as a result of an increase in the FERC-mandated interest rate (see Note 15 of the Notes to the Consolidated Financial Statements). In addition, interest expense related to \$1.2 billion in long-term debt issued in 2007 and variable rate pollution control bond loan agreements increased by approximately \$40 million. These increases were partially offset by a reduction of approximately \$34 million in the interest expense related to the declining balance of the ERBs and RRBs. In addition, other interest expense, including lower interest expense on balances in certain regulatory balancing accounts, decreased approximately \$3 million.

The Utility's interest expense in 2009 and future periods will be impacted by changes in interest rates, as well as by changes in the amount of debt outstanding as long-term debt matures and additional long-term debt is issued (see "Liquidity and Financial Resources" below for further discussion).

Other Income (Expense), Net

The Utility's other income (expense), net decreased by approximately \$24 million, or 63%, in 2008 compared to 2007. This decrease is primarily due to an increase in costs of approximately \$24 million that was spent in 2008 to oppose the statewide initiative related to renewable energy (Proposition 7) and the City of San Francisco's municipalization efforts.

Income Tax Expense

The Utility's income tax expense decreased by approximately \$83 million, or 15%, in 2008 compared to 2007. The effective tax rates were 28.9% and 35.8% for 2008 and 2007, respectively. The decrease in the effective tax rate for 2008 was primarily due to a settlement of federal tax audits for the tax years 2001 through 2004 and approval by the Internal Revenue Service ("IRS") of the Utility's change in accounting method for the capitalization of indirect service costs for tax years 2001 through 2004. (See "Tax Matters" below and Note 10 of the Notes to the Consolidated Financial Statements for a discussion of "Income Taxes".)

The Utility's income tax expense decreased by approximately \$31 million, or 5%, in 2007 compared to 2006, primarily due to a decrease of approximately \$29 million as a result of fixed asset related tax deductions, due to an increase in tax-deductible decommissioning expense in 2007 compared to 2006. The effective tax rates were 35.8% and 38.0% for 2007 and 2006, respectively.

PG&E Corporation, Eliminations, and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to its 9.50% Convertible Subordinated Notes and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating revenues and expenses in 2008 compared to 2007 and 2007 compared to 2006.

Other Expense, Net

PG&E Corporation's other expense increased by approximately \$23 million, or 255%, in 2008 compared to 2007, primarily due to an increase in investment losses in the rabbi trusts related to the non-qualified deferred compensation plans.

Income Tax Benefit

PG&E Corporation's income tax benefit increased by approximately \$31 million, or 97%, in 2008 compared to 2007, primarily due to a settlement of federal tax audits for the tax years 2001 through 2004.

Discontinued Operations

In the fourth quarter of 2008, PG&E Corporation reached a settlement of federal tax audits of tax years 2001 through 2004 and recognized after-tax income of approximately \$257 million. Approximately \$154 million of this amount relates to losses incurred and synthetic fuel tax credits claimed by PG&E Corporation's former subsidiary NEGTEC. As a result, PG&E Corporation recorded \$154 million in income from discontinued operations in 2008. (See Note 6 of the Notes to the Consolidated Financial Statements for further discussion.)

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations depends on the levels of its operating cash flow and access to the capital markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal demand for electricity and natural gas, volatility in energy commodity costs, collateral requirements related to price risk management activity, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and financings, among other factors. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures, and relies on short-term debt to fund temporary financing needs.

The CPUC has authorized the Utility to incur \$2 billion of short-term debt for working capital fluctuations and energy procurement-related purposes, and an additional \$500 million for certain CPUC-defined extraordinary events. The recent disruption in the capital markets has made it challenging for companies to access the markets for commercial paper and new credit facilities. Notwithstanding this volatility, the Utility has continued to have access to the commercial paper market, albeit at higher prices and with shorter duration at times.

PG&E Corporation's ability to fund operations and capital expenditures, make scheduled principal and interest payments, refinance debt, fund Utility equity contributions, and make dividend payments primarily depends on the level of cash distributions received from the Utility and access to the capital markets. PG&E Corporation contributes equity to the Utility as needed for the Utility to maintain its CPUC-authorized capital structure. These equity contributions have been funded primarily through the issuance of common stock.

The following table summarizes PG&E Corporation's and the Utility's cash positions:

(in millions)	December 31,	
	2008	2007
PG&E Corporation	\$ 167	\$ 204
Utility	52	141
Total consolidated cash and cash equivalents	219	345
Utility restricted cash	1,290	1,297
Total consolidated cash, including restricted cash	\$ 1,509	\$ 1,642

Restricted cash primarily consists of cash held in escrow pending the resolution of the remaining disputed claims filed in the Utility's reorganization proceeding under Chapter 11. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in money market funds.

Credit Facilities and Short-Term Borrowings

The Utility has a \$2 billion revolving credit facility and PG&E Corporation has a \$200 million revolving credit facility. Each of PG&E Corporation's and the Utility's revolving credit facilities include commitments from a well-diversified syndicate of lenders. Neither credit facility permits the lenders to refuse funding a draw solely due to the occurrence of a "material adverse effect" as defined in the facilities. No single lender's commitment represents more than 11% of total borrowing capacity under either facility. As of December 31, 2008, the commitment from Lehman Brothers Bank, FSB ("Lehman Bank") represented approximately \$13 million, or 7%, of the total borrowing capacity under PG&E Corporation's \$200 million revolving credit facility and approximately \$60 million, or 3%, of the Utility's \$2.0 billion revolving credit facility. Lehman Bank has failed to fund its portion of borrowings under the Utility's revolving credit facility since September 2008 and neither the Utility nor PG&E Corporation expects that Lehman Bank will fund any future borrowings or letter of credit draws.

The Utility has a \$1.75 billion commercial paper program, the borrowings from which are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the revolving credit facility. At December 31, 2008, the average yield was approximately 2.48%.

The following table summarizes PG&E Corporation and the Utility's short-term borrowings and outstanding credit facilities at December 31, 2008:

(in millions)	At December 31, 2008						
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Revolving credit facility	February 2012	\$ 200 ⁽¹⁾	\$ -	\$ -	\$ -	\$ 200
Utility	Revolving credit facility	February 2012	2,000 ⁽²⁾	287	-	287	1,426
Total credit facilities			\$ 2,200	\$ 287	\$ -	\$ 287	\$ 1,626

⁽¹⁾ Includes a \$50 million sublimit for letters of credit and \$100 million sublimit for "swingline" loans, defined as loans which are made available on a same-day basis and are repayable in full within 30 days.

⁽²⁾ Includes a \$950 million sublimit for letters of credit and \$100 million sublimit for swingline loans.

PG&E Corporation's and the Utility's revolving credit facilities include usual and customary covenants for credit facilities of their type, including covenants limiting liens to those permitted under the senior notes' indenture, mergers, sales of all or substantially all of the Utility's assets, and other fundamental changes. In addition, both PG&E Corporation and the Utility are required to maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and PG&E Corporation must own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility. At December 31, 2008, PG&E Corporation and the Utility met all of these requirements.

2008 Financings

Access to the capital markets is essential to the continuation of the Utility's capital expenditure program. Notwithstanding the recent disruption in the capital markets, the Utility was able to issue \$1.2 billion of senior unsecured notes in October and November 2008. The proceeds were used primarily to finance capital expenditures and to partially repay outstanding commercial paper balances in preparation for refinancing \$600 million of long-term debt that will mature in March 2009. In addition, the Utility used the proceeds it received from the September and October 2008 refunding of certain pollution control bonds to repay outstanding commercial paper.

The following table summarizes the Utility's long-term debt issuances in 2008:

(in millions)	Issue Date	Amount
Senior notes		
5.625%, due 2017	March 3	\$ 200
6.35%, due 2038	March 3	400
8.25%, due 2018	October 21	600
6.25%, due 2013	November 18	400
8.25%, due 2018	November 18	200
Total senior notes		1,800
Pollution control bonds		
Series 2008 F, 3.75%, due 2026	September 22	50
Series 2008 G, 3.75%, due 2018	September 22	45
Series 2008 A and B, variable rates, due 2026	October 29	149
Series 2008 C and D, variable rates, due 2016	October 29	160
Total pollution control bonds		404
Total long-term debt issuances in 2008		\$ 2,204

During 2008, PG&E Corporation issued 6,905,462 shares of common stock upon exercise of employee stock options, for the account of 401(k) participants, and under its Dividend Reinvestment and Stock Purchase Plan, generating approximately \$225 million of cash. In 2008 PG&E Corporation contributed \$270 million of cash to the Utility to ensure that the Utility had adequate capital to fund its capital expenditures and to maintain the 52% common equity ratio authorized by the CPUC.

Future Financing Needs

The amount and timing of the Utility's future financing needs will depend on various factors, including the conditions in the capital markets and the Utility's ability to access the capital markets, the timing and amount of forecasted capital expenditures, and the amount of cash internally generated through normal business operations, among other factors. The Utility's future financing needs will also depend on the timing of the resolution of the disputed claims and the amount of interest on these claims that the Utility will be required to pay. (See Note 15 of the Notes to the Consolidated Financial Statements.)

Assuming continued access to the capital markets, the Utility currently plans to issue additional long-term debt of \$3.5 billion to \$4.5 billion through 2011. PG&E Corporation expects to issue additional common stock, debt, or other securities, depending on market conditions, to fund a portion of its equity contributions to the Utility and to fund PG&E Corporation's capital expenditures. PG&E Corporation currently plans to contribute equity of \$1.2 billion to \$1.8 billion to the Utility through 2011. Assuming that PG&E Corporation and the Utility can access the capital markets on reasonable terms, PG&E Corporation and the Utility believe that the Utility's cash flow from operations, existing sources of liquidity, and future financings will provide adequate resources to fund operating activities, meet anticipated obligations, and finance future capital expenditures.

Credit Ratings

As of January 31, 2009, PG&E Corporation and the Utility's credit ratings from Moody's and Standard & Poor's ("S&P") were as follows:

	Moody's	S&P
Utility		
Corporate credit rating	A3	BBB+
Senior unsecured debt	A3	BBB+
Credit facility	A3	BBB+
Pollution control bonds backed by letters of credit	Not rated to Aa1/VMIG1	AA-/A-1+ to AAA/A-1+
Pollution control bonds backed by bond insurance	A3	A to AA
Pollution control bonds – nonbacked	A3	BBB+
Preferred stock	Baa2	BBB-
Commercial paper program	P-2	A-2
PG&E Energy Recovery Funding LLC		
Energy recovery bonds	Aaa	AAA
PG&E Corporation		
Corporate credit rating	Baa1	Not rated
Credit facility	Baa1	Not rated

Moody's and S&P are nationally recognized credit rating organizations. These ratings may be subject to revision or withdrawal at any time by the assigning rating organization and each rating should be evaluated independently of any other rating. A credit rating is not a recommendation to buy, sell, or hold securities.

Dividends

The dividend policies of PG&E Corporation and the Utility are designed to meet the following three objectives:

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

The Boards of Directors of PG&E Corporation and the Utility have each adopted a target dividend payout ratio range of 50% to 70% of earnings. Dividends paid by PG&E Corporation and the Utility are expected to remain in the lower end of the target payout ratio range to ensure that equity funding is readily available to support each company's capital investment needs. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change their view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

In addition, the declaration of the Utility's dividends is subject to the CPUC-imposed conditions that the Utility maintain on average its CPUC-authorized capital structure and that the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, be given first priority.

During 2008, the Utility paid common stock dividends totaling \$589 million, including \$568 million of common stock dividends paid to PG&E Corporation and \$21 million of common stock dividends paid to PG&E Holdings, LLC. At December 31, 2007, PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, held 19,481,213 shares of the Utility common stock. Effective August 29, 2008, PG&E Holdings LLC, was dissolved, and the shares subsequently cancelled.

During 2008, PG&E Corporation paid common stock dividends of \$1.53 per share totaling \$573 million, including \$28 million that was paid to Elm Power Corporation. (At December 31, 2007, Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, held 24,665,500 shares of PG&E Corporation common stock. Effective August 29, 2008, Elm Power Corporation was dissolved, and the shares subsequently cancelled.) On December 17, 2008, the Board of Directors of PG&E Corporation declared a dividend of \$0.39 per share, totaling \$141 million, which was paid on January 15, 2009 to shareholders of record on December 31, 2008. On February 18, 2009, the Board of Directors of PG&E Corporation declared a dividend of \$0.42 per share, payable on April 15, 2009, to shareholders of record on March 31, 2009.

During 2008, the Utility paid cash dividends to holders of its outstanding series of preferred stock totaling \$14 million. On December 17, 2008, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock totaling approximately \$3 million that was paid on February 15, 2009, to preferred shareholders of record on January 30, 2009. On February 18, 2009, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock, payable on May 15, 2009, to shareholders of record on April 30, 2009.

Utility

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for 2008, 2007, and 2006 were as follows:

(in millions)	2008	2007	2006
Net income	\$ 1,199	\$ 1,024	\$ 985
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,838	1,956	1,802
Allowance for equity funds used during construction	(70)	(64)	(47)
Gain on sale of assets	(1)	(1)	(11)
Deferred income taxes and tax credits, net	593	43	(287)
Other changes in noncurrent assets and liabilities	(25)	188	116
Effect of changes in operating assets and liabilities:			
Accounts receivable	(83)	(6)	128
Inventories	(59)	(41)	34
Accounts payable	(137)	(196)	21
Income taxes receivable/payable	43	56	28
Regulatory balancing accounts, net	(394)	(567)	329
Other current assets	(223)	170	(273)
Other current liabilities	90	24	(235)
Other	(5)	(45)	(13)
Net cash provided by operating activities	\$ 2,766	\$ 2,541	\$ 2,577

During 2008, net cash provided by operating activities was approximately \$2,766 million, reflecting net income of \$1,199 million, adjusted for noncash depreciation, amortization, and decommissioning and allowance for equity funds used during construction of \$1,838 million and \$70 million, respectively (see “Results of Operations” above). Additionally, the following change in operating assets and liabilities positively impacted cash flows during the period:

- Liabilities for deferred income taxes and tax credits increased by approximately \$593 million in 2008, primarily due to an increase in balancing account revenues, which are not taxable until billed, as well as an increase in deductible tax depreciation as authorized by the 2008 Economic Stimulus Act.

The following changes in operating assets and liabilities negatively impacted cash flows during the period:

- Regulatory balancing accounts, net under-collection increased by approximately \$394 million in 2008, primarily due to an increase of approximately \$356 million in under-collected electricity procurement costs and a \$108 million decrease in over-collections due to refunds to customers for the over-collected prior year balance. The 2007 over-collection was caused by lower than forecasted RMR costs and the receipt of a settlement payment made in connection with an energy supplier refund claim. This increase in the Regulatory balancing accounts, net under-collection was partially offset by a refund of approximately \$230 million that the Utility received from the California Energy Commission (“CEC”). The funds from the CEC will be refunded to customers in 2009.
- Net collateral paid, primarily related to price risk management activities, increased by approximately \$325 million in 2008 as a result of changes in the Utility’s exposure to counterparties’ credit risk, generally reflecting declining natural gas prices. Collateral payables and receivables are included in Other changes in noncurrent assets and liabilities, Other current assets, and Other current liabilities in the table above.

During 2007, net cash provided by operating activities was approximately \$2,541 million, reflecting net income of \$1,024 million, adjusted for noncash depreciation, amortization, and decommissioning and allowance for equity funds used during construction of \$1,956 million and \$64 million, respectively (see “Results of Operations” above). The following changes in operating assets and liabilities positively impacted cash flows during the period:

- Other noncurrent assets and liabilities increased by approximately \$188 million primarily due to \$159 million of under-spent funds related to the California Solar Incentive program.
- Other current assets decreased by approximately \$170 million primarily due to a decrease in the cash collateral deposited by counterparties as a result of changes in the Utility’s exposure to counterparties’ credit risk.

The following changes in operating assets and liabilities negatively impacted cash flows during the period:

- Regulatory balancing accounts, net over-collection decreased by approximately \$567 million in 2007 primarily due to CPUC-authorized rate reductions designed to reduce the over-collection.
- Accounts payable decreased by approximately \$196 million primarily due to differences in the timing of purchases and payments of operating expenses.

During 2006, net cash provided by operating activities was approximately \$2,577 million, reflecting net income of \$985 million, adjusted for noncash depreciation, amortization, and decommissioning and allowance for equity funds used during construction of \$1,802 million and \$47 million, respectively (see “Results of Operations” above). The following change in operating assets and liabilities positively impacted cash flows during the period:

- Regulatory balancing accounts, net under-collection decreased by approximately \$329 million in 2006, primarily due to lower than forecasted costs associated with certain power purchase agreements and a decrease related to customer energy efficiency incentives due to a CPUC decision in October 2005 to set rates to recover shareholder incentive revenue. These decreases were offset by a decrease in electricity procurement costs due to the receipt of cash relating to the Mirant settlement.

The following changes in operating assets and liabilities negatively impacted cash flows during the period:

- Liabilities for deferred income taxes and tax credits decreased by approximately \$287 million in 2006, primarily due to an increased California franchise tax deduction, lower taxable supplier settlement income received, and a deduction related to the payment of previously accrued litigation costs.
- Other current assets increased by approximately \$273 million primarily due to an increase in the cash collateral deposited by counterparties as a result of changes in the Utility’s exposure to counterparties’ credit risk, generally reflecting increasing natural gas prices.
- Other current liabilities decreased by approximately \$235 million primarily due to the settlement of claims related to the alleged exposure to chromium at the Utility’s natural gas compressor stations.

Future operating cash flow will be impacted by the timing of cash collateral payments and receipts related to price risk management activity, among other factors. The Utility’s cash collateral activity will fluctuate based on changes in the Utility’s net credit exposure, which is primarily dependent on electricity and gas price movement.

In addition, PG&E Corporation and the Utility’s future operating cash flow in 2009 is expected to be impacted by the receipt of tax refunds. (See “Tax Matters” below and Note 10 of the Notes to the Consolidated Financial Statements.)

The Utility's operating cash flows also will be impacted by electricity procurement costs and the timing of rate adjustments authorized to recover these costs. The CPUC has established a balancing account mechanism to adjust the Utility's electric rates whenever the forecasted aggregate over-collections or under-collections of the Utility's electric procurement costs for the current year exceed 5% of the Utility's prior year generation revenues, excluding generation revenues for DWR contracts. In accordance with this mechanism, on August 21, 2008, the CPUC approved the Utility's request to collect from customers the forecasted 2008 end-of-year under-collection of procurement costs, due mainly to rising natural gas costs and lower than forecasted hydroelectric generation. Effective October 1, 2008, customer rates were adjusted to allow the Utility to collect \$645 million in procurement costs through December 2009. On December 30, 2008, the Utility requested that its electric rates be adjusted, effective January 1, 2009, to reflect the revised forecast of electricity prices which are expected to be lower than originally forecasted as a result of lower natural gas prices. The January 1, 2009 rate changes reflect a net decrease of \$101 million in electric revenues versus revenues based on rates effective October 1, 2008. On January 23, 2009, the Utility filed a notice with the CPUC indicating that customer electric rates are expected to increase effective on March 1, 2009 by approximately \$640 million as a result of the CPUC's approval of a \$528 million increase in the remittance rate paid to the DWR and the FERC's approval of a \$112 million increase in electric transmission rates.

In addition, the ongoing upheaval in the economy has negatively impacted investment returns on assets held in trust to satisfy the Utility's obligations to decommission its nuclear generation facilities and to secure payment of employee benefits under pension and other post-retirement benefit plans. The Utility's recorded liabilities and, in some cases, its funding obligations, may increase as a result of declining investment returns on trust assets and lower assumed rates of return. However, the Utility believes that it is probable that any increase in funding obligations would be recoverable through rates, and as a result is not expected to have a material impact on the Utility's cash flows or results of operations.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash used in investing activities depends primarily upon the amount and type of construction activities, which can be influenced by the need to make electricity and natural gas reliability improvements, storms, and other factors.

The Utility's cash flows from investing activities for 2008, 2007, and 2006 were as follows:

(in millions)	2008	2007	2006
Capital expenditures	\$ (3,628)	\$ (2,768)	\$ (2,402)
Net proceeds from sale of assets	26	21	17
Decrease in restricted cash	36	185	115
Proceeds from nuclear decommissioning trust sales	1,635	830	1,087
Purchases of nuclear decommissioning trust investments	(1,684)	(933)	(1,244)
Other	(25)	-	1
Net cash used in investing activities	\$ (3,640)	\$ (2,665)	\$ (2,426)

Net cash used in investing activities increased by approximately \$975 million in 2008 compared to 2007 and by approximately \$239 million in 2007 compared to 2006. These increases were primarily due to increases of approximately \$860 million and \$366 million in 2008 and 2007, respectively, of capital expenditures for installing the SmartMeter™ advanced metering infrastructure, generation facility spending, replacing and expanding gas and electric distribution systems, and improving the electric transmission infrastructure. (See "Capital Expenditures" below.)

Future cash flows used in investing activities are largely dependent on expected capital expenditures. (See "Capital Expenditures" below for further discussion of expected spending and significant capital projects.)

Financing Activities

The Utility's cash flows from financing activities for 2008, 2007, and 2006 were as follows:

(in millions)	2008	2007	2006
Borrowings under accounts receivable facility and revolving credit facility	\$ 533	\$ 850	\$ 350
Repayments under accounts receivable facility and revolving credit facility	(783)	(900)	(310)
Net issuance (repayments) of commercial paper, net of discount of \$11 million in 2008, \$1 million in 2007 and \$2 million in 2006	6	(209)	458
Proceeds from issuance of long-term debt, net of discount, premium, and issuance costs of \$19 million in 2008 and \$16 million in 2007	2,185	1,184	-
Long-term debt repurchased	(454)	-	-
Rate reduction bonds matured	-	(290)	(290)
Energy recovery bonds matured	(354)	(340)	(316)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(568)	(509)	(460)
Equity contribution	270	400	-
Other	(36)	23	38
Net cash provided by (used in) financing activities	\$ 785	\$ 195	\$ (544)

In 2008, net cash provided by financing activities increased by approximately \$590 million compared to 2007. In 2007, net cash provided by financing activities increased by approximately \$739 million compared to 2006. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depends on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures, and relies on short-term debt to fund temporary financing needs.

PG&E Corporation

With the exception of dividend payments, interest, and transactions between PG&E Corporation and the Utility, PG&E Corporation had no material cash flows on a stand-alone basis for the years ended December 31, 2008, 2007, and 2006.

CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation and the Utility's contractual commitments at December 31, 2008.

(in millions)	Payment due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual Commitments:					
Utility					
Long-term debt ⁽¹⁾ :					
Fixed rate obligations	\$ 17,125	\$ 1,089	\$ 1,540	\$ 1,314	\$ 13,182
Variable rate obligations	954	7	332	615	-
Energy recovery bonds ⁽²⁾	1,742	435	871	436	-
Purchase obligations:					
Power purchase agreements ⁽³⁾ :					
Qualifying facilities	12,979	1,361	2,649	2,221	6,748
Renewable contracts	9,779	439	1,076	1,278	6,986
Irrigation district and water agencies	372	64	135	89	84
Other power purchase agreements	1,945	275	458	171	1,041
Natural gas supply and transportation	1,444	898	298	91	157
Nuclear fuel	950	95	200	160	495
Pension and other benefits ⁽⁴⁾	580	300	280	-	-
Capital lease obligations ⁽⁵⁾	454	50	100	100	204
Operating leases	123	21	35	33	34
Preferred dividends ⁽⁶⁾	70	14	28	28	-
Other commitments	24	24	-	-	-
PG&E Corporation					
Long-term debt ⁽¹⁾ :					
Convertible subordinated notes	318	27	291	-	-

⁽¹⁾ Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2008 and outstanding principal for each instrument with the terms ending at each instrument's maturity. Variable rate obligations consist of bonds, due in 2016-2026, backed by letters of credit which expire in 2011 and 2012. These bonds are subject to mandatory redemption unless the letters of credit are extended or replaced or if applicable to the series, the issuer consents to the continuation of these bonds without a credit facility. Accordingly, these bonds have been classified for repayment purposes in 2011 and 2012. (See Note 4 of the Notes to the Consolidated Financial Statements.)

⁽²⁾ Includes interest payments over the terms of the bonds. (See Note 5 of the Notes to the Consolidated Financial Statements.)

⁽³⁾ This table does not include DWR allocated contracts because the DWR is legally and financially responsible for these contracts and payments. (See Note 17 of the Notes to the Consolidated Financial Statements.)

⁽⁴⁾ PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions, sufficient to meet minimum funding requirements. (See Note 14 of the Notes to the Consolidated Financial Statements.)

⁽⁵⁾ See Note 17 of the Notes to the Consolidated Financial Statements.

⁽⁶⁾ Based on historical performance, it is assumed for purposes of the table above that dividends are payable within a fixed period of five years.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2008, the Utility was committed to spending approximately \$228 million for these conversions. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties and telephone utilities involved. The Utility expects to spend approximately \$40 million to \$60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

The contractual commitments table above also excludes potential payments associated with unrecognized tax benefits accounted for under Financial Accounting Standards Board ("FASB") Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," ("FIN 48"). Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amount and period of future payments to major tax jurisdictions related to FIN 48 liabilities. Matters relating to tax years that remain subject to examination are discussed below and in Note 10 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's investment in property, plant and equipment totaled \$3.7 billion in 2008, \$2.8 billion in 2007, and \$2.4 billion in 2006. The Utility expects that capital expenditures will total approximately \$3.6 billion in 2009 and forecasts that capital expenditures will average approximately \$3.5 to \$4.0 billion per year over the next three years. The Utility's weighted average rate base in 2008 was \$18.2 billion. Based on the estimated capital expenditures for 2009, the Utility projects a weighted average rate base of approximately \$20.1 billion for 2009. Depending on conditions in the capital markets, the Utility forecasts that it will make various capital investments in its electric and gas transmission and distribution infrastructure to maintain and improve system reliability, safety, and customer service; to extend the life of or replace existing infrastructure; and to add new infrastructure to meet already authorized growth. Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC and TO rate cases. In addition, from time to time, the Utility requests authorization to collect additional revenue requirements to recover capital expenditures related to specific projects, such as new power plants, gas or electric transmission projects, and the SmartMeterTM advanced metering infrastructure.

Proposed Electric Distribution Reliability Program (Cornerstone Improvement Program)

On December 19, 2008, the CPUC ruled that it will consider the Utility's request for approval of a proposed six-year electric distribution reliability improvement program. The CPUC found that it is preferable to begin the scrutiny and detailed analyses to determine whether major capital expenditures are necessary to maintain or improve distribution reliability and, if necessary, to determine the extent and timing of such expenditures, sooner rather than later. The proposed program includes initiatives that are designed to decrease the frequency and duration of electricity outages in order to bring the Utility's reliability performance closer to that of other investor-owned electric utilities. The Utility expects that the work performed in the six-year program also would provide additional reliability benefits. The Utility forecasts that it would incur capital expenditures totaling approximately \$2.3 billion and operating and maintenance expenses totaling approximately \$43 million over the six-year period. In its December 19, 2008 decision, the CPUC ruled that program costs incurred in 2009 and 2010, if any, would not be recoverable from customers. The Utility does not expect to incur significant costs in 2009 or 2010 before the CPUC issues a final decision on the Utility's request.

PG&E Corporation and the Utility cannot predict whether the CPUC will approve the Utility's request.

Proposed Electric Transmission Projects

The Utility has been exploring the feasibility of obtaining regulatory approval for a potential investment in an electric transmission project that would traverse the Pacific Northwest. On April 17, 2008, the FERC granted part of the Utility's request for a declaratory order to collect transmission rates designed to provide an incentive to the Utility to continue leading the development of the proposed 1,000-mile, 500 kilovolt ("kV") transmission line to run from British Columbia, Canada to Northern California that would provide access to potential new renewable generation resources, improve regional transmission reliability, and provide opportunities for other market participants to use the new facilities. The FERC's order allows the Utility to recover all prudently incurred pre-commercial costs, such as costs for feasibility studies and surveys, and all prudently incurred development and construction costs if the proposed project is abandoned or cancelled for reasons beyond the Utility's control. On December 1, 2008, the Western Electric Coordinating Council ("WECC") formally completed the Regional Planning Project Review process for the project. On December 19, 2008, the Utility submitted to WECC a plan-service and technical studies showing that the desired line rating of 3,000 megawatts north to south is achievable; the south to north rating study is underway. The target operating date for the project is December 2015. The development and construction of this proposed transmission project remains subject to significant business, financial, regulatory, environmental, and political risks and challenges.

The Utility also has been exploring the development of a new 500-kV electric transmission project, the Central California Clean Energy Transmission line, to increase transmission capacity between northern and southern California, improve access to new renewable generation resources and meet reliability requirements in the Fresno area. The CAISO has been conducting stakeholder meetings to review the Utility's proposal and the Utility has been conducting various studies to ensure that the project is designed and located to avoid or minimize potential impacts. Depending on the results of these stakeholder meetings and studies, the Utility will decide whether to request CPUC approval to construct the line.

The Utility cannot predict whether the many conditions and challenges to the development of these proposed electric transmission projects will be met.

Potential Natural Gas Pipeline Projects

PG&E Corporation, through its subsidiary, PG&E Strategic Capital, Inc., along with Fort Chicago Energy Partners, L.P. and Northwest Pipeline Corporation, have agreed to jointly pursue the development of the proposed 230-mile Pacific Connector Gas Pipeline that would connect the proposed Jordan Cove liquefied natural gas ("LNG") terminal in Coos Bay, Oregon with the Utility's transmission system near Malin, Oregon. The development of the Pacific Connector Gas Pipeline is dependent upon the development of the Jordan Cove LNG terminal by Fort Chicago Energy Partners, L.P. In addition, the development and construction of the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline are subject to obtaining permits, regulatory approvals, and commitments under long-term capacity contracts. It is expected that the FERC will issue a certificate authorizing construction and operation of the pipeline in 2009.

SmartMeter™ Program

Since late 2006, the Utility has been installing an advanced metering infrastructure, known as the SmartMeter™ program, for virtually all of the Utility's electric and gas customers. This infrastructure results in substantial cost savings associated with billing customers for energy usage, and enables the Utility to measure usage of electricity on a time-of-use basis and to charge time-differentiated rates. The main goal of time-differentiated rates is to encourage customers to reduce energy consumption during peak demand periods and to reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility expects to complete the installation throughout its service territory by the end of 2011.

The CPUC authorized the Utility to recover the \$1.74 billion estimated SmartMeter™ project cost, including an estimated capital cost of \$1.4 billion. The \$1.74 billion amount includes \$1.68 billion for project costs and approximately \$54.8 million for costs to market critical peak pricing programs such as SmartRate that are made possible by SmartMeter™ technology. In addition, the Utility can recover in rates 90% of up to \$100 million in costs that exceed \$1.68 billion without a reasonableness review by the CPUC. The remaining 10% will not be recoverable in rates. If additional costs exceed the \$100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review. Through 2008, the Utility has spent an aggregate of \$730 million, including capital costs of \$589 million, to install the SmartMeter™ system.

On December 12, 2007, and supplemented on May 14, 2008, the Utility filed an application with the CPUC requesting approval to upgrade elements of the SmartMeter™ program at an estimated cost of approximately \$572 million, including approximately \$463 million of capital expenditures to be recovered through electric rates beginning in 2009. The Utility has proposed to install upgraded electric meters with associated devices that would offer an expanded range of service features for electric customers that would provide energy conservation and demand response options, such as the enablement of "smart" appliances that could use energy more wisely in response to near real-time energy data. These upgraded meters would also increase operational efficiencies for the Utility through, among other things, the ability to remotely connect and disconnect service to electric customers. In addition, the upgraded electric meters are designed to facilitate the Utility's ability to incorporate future advanced metering technology innovations in a timely and cost-effective manner.

On December 23, 2008, a proposed decision was issued by an administrative law judge, which if adopted by the CPUC, would allow the Utility to proceed with the SmartMeter Upgrade and authorize funding of \$495.2 million, including \$410 million in capital costs, to be recovered through an increased revenue requirement. PG&E Corporation and the Utility are unable to predict when the CPUC will issue a final decision.

On July 31, 2008, the CPUC ordered the Utility to implement "dynamic pricing" electric rates in 2010 and 2011 for certain customers who do not take affirmative action to opt out of the dynamic pricing rates. Dynamic pricing rates use price signals (e.g., critical peak pricing and real-time pricing) to encourage energy efficiency and reduce demand. The Utility is required to implement critical peak pricing rates for these customers starting in 2010 and early 2011. The Utility is also required to offer real-time pricing to all customers starting in May 2011, at the customer's election. The Utility has been directed to file a request with the CPUC by February 28, 2009 to approve the Utility's rate proposal for critical peak pricing and to authorize recovery of the Utility's estimated costs of approximately \$155 million (including estimated capital costs of approximately \$107 million) to meet the required schedule for implementation. The Utility expects to file a request for approval of real-time pricing rates and the associated implementation costs by March 1, 2010 in connection with the Utility's 2011 GRC proceeding.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC authorized the Utility to replace the steam generators at the two nuclear operating units at Diablo Canyon (Units 1 and 2) and recover costs up to \$706 million from customers without further reasonableness review. If costs exceed this threshold, the CPUC authorized the Utility to recover costs of up to \$815 million, subject to reasonableness review of the full amount. As of December 31, 2008, the Utility has spent approximately \$554 million, including progress payments under contracts for the eight steam generators that the Utility has ordered. The Utility anticipates the future expenditures will be approximately \$146 million. The Utility installed four of the new steam generators in Unit 2 during the refueling outage that began in February 2008 and ended in April 2008. The extended refueling outage to replace the steam generators in Unit 1 began in January and is expected to end in early April 2009.

New Generation Facilities

During 2008, the Utility was engaged in the development of the following generation facilities to be owned and operated by the Utility:

Gateway Generating Station

In November 2006, the Utility acquired the equipment, permits and contracts related to a partially completed 530-megawatt ("MW") power plant in Antioch, California, referred to as the Gateway Generating Station. The CPUC has authorized the Utility to recover estimated capital costs of approximately \$385 million to complete the construction of the facility and as of December 31, 2008, the Utility has incurred approximately \$350 million. Of this amount, the Utility incurred \$221 million during 2008. The Gateway Generating Station reached full load commercial production on January 4, 2009, and is expected to reach final project completion at the end of the first quarter of 2009.

Colusa Generating Station

On June 12, 2008, the CPUC gave its final approval for the Utility to construct the Colusa Generating Station, a 657- MW combined cycle generating facility to be located in Colusa County, California. Final environmental permitting was approved on September 29, 2008 and construction began on October 1, 2008.

The CPUC authorized the Utility to recover an initial capital cost for the Colusa Generating Station of approximately \$673 million that can be adjusted to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. The CPUC authorized the Utility to seek recovery of additional capital costs attributable to operational enhancements, but otherwise limited cost recovery to the initial capital cost estimate. The CPUC also ruled that in the event the final capital costs are lower than the initial estimate, half of the savings must be returned to customers. If actual costs exceed the cost limits (except for additional capital costs attributable to operational enhancements), the Utility would be unable to recover such excess costs. The forecasted initial capital cost will be trued up in the Utility's next GRC following the commencement of operations to reflect actual initial capital costs. Permitting or construction delays and project development or materials cost overruns could cause the project costs to exceed the CPUC-adopted cost limits. As of December 31, 2008, the Utility had incurred \$216 million for the development and construction of the Colusa Generating Station. Of this amount, the Utility has incurred \$204 million during 2008.

Subject to meeting operational performance requirements and other conditions, it is anticipated that the Colusa Generating Station will commence operations in 2010.

Humboldt Bay Generating Station

On September 24, 2008, the CEC issued its final decision authorizing the construction of a 163-MW power plant to re-power the Utility's existing power plant at Humboldt Bay, which is at the end of its useful life. Demolition of existing structures on the site is complete and the contractor began preparing the site for construction in December 2008.

The CPUC authorized the Utility to recover an initial capital cost for the Humboldt Bay Generating Station of approximately \$239 million for the construction that can be adjusted to reflect any actual incentive payments made to, or liquidated damages received from, the contractors through notification to the CPUC but without a reasonableness review. The Utility is authorized to seek recovery of additional capital costs that are attributable to operational enhancements, but the request will be subject to the CPUC's review. The Utility also is permitted to seek recovery of additional capital costs subject to a reasonableness review. The forecasted initial capital cost will be trued up in the Utility's next GRC following the commencement of operations to reflect actual initial capital costs. Permitting or construction delays and project development or materials cost overruns could cause the project costs to exceed the CPUC-adopted cost limits. As of December 31, 2008, the Utility had incurred \$61.5 million for the development and construction of the Humboldt Bay Generating Station. Of this amount, the Utility incurred \$55 million during 2008.

Subject to obtaining required permits, meeting construction schedules, operational performance requirements and other conditions, it is anticipated that the Humboldt Bay project will commence operations in 2010.

Proposed New Generation Facilities

Request for Long-Term Generation Resources

The Utility's CPUC-approved long-term electricity procurement plan, covering 2007-2016, forecasts that the Utility will need to obtain an additional 800 to 1,200 MW of new generation resources by 2015 above the Utility's planned additions of renewable resources, energy efficiency, demand reduction programs, and previously approved contracts for new generation resources. The CPUC allows the California investor-owned utilities to acquire ownership of new conventional generation resources only through purchase and sale agreements ("PSAs") (i.e., a PSA is a "turnkey" arrangement in which a new generating facility is constructed by a third party and then sold to the Utility upon satisfaction of certain contractual requirements) and engineering, procurement, and construction arrangements proposed by third parties. The utilities are prohibited from submitting offers for utility-built generation in their respective requests for offers ("RFOs") until questions can be resolved about how to compare utility-owned generation offers with offers from independent power producers. The utilities are permitted to propose utility-owned generation projects through a separate application outside of the RFO process in the following circumstances: (1) to mitigate market power demonstrated by the utility to be held by others, (2) to support a use of preferred resources, such as renewable energy sources, (3) to take advantage of a unique and fleeting opportunity (such as a bankruptcy settlement), and (4) to meet unique reliability needs.

On July 21, 2008, the Utility received offers from third parties in response to the Utility's April 1, 2008 RFO for 800 MW to 1,200 MW of dispatchable and operationally flexible new generation resources to be on-line no later than May 2015. The Utility's RFO requested offers for both PSAs and power purchase. In the fourth quarter of 2008, the Utility developed its RFO shortlist of participants and is currently involved in negotiations with potential counterparties. The Utility anticipates executing contracts and requesting CPUC approval of the executed contracts in the first half of 2009.

Proposed Renewable Energy Development

California law establishes a renewable portfolio standard ("RPS") that requires that each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity delivered from renewable resources equals at least 20% of its total retail sales by the end of 2010. The California Legislature also is considering legislation to increase the RPS to require 33% of a retail seller's electric load to be met with renewable resources by 2020.

Following several RFOs and bilateral negotiations, the Utility entered into various agreements to purchase renewable generation to be produced by facilities proposed to be developed by third parties. The development of these renewable generation facilities are subject to many risks, including risks related to permitting, financing, technology, fuel supply, environmental, and the construction of sufficient transmission capacity. The Utility has been supporting the development of these renewable resources by working with regulatory and governmental agencies to ensure timely construction of transmission lines and permitting of proposed project sites.

In addition, to help meet the challenging RPS goal by 2010, the Utility intends to explore developing and/or owning renewable generation resources, subject to CPUC approval. In particular, on February 24, 2009, the Utility requested the CPUC to approve the Utility's proposed development of renewable generation resources based on solar photovoltaic ("PV") technology. The Utility's proposal includes the development and construction of up to 250 MW of Utility-owned PV generating facilities, to be deployed over a period of five years, at an estimated capital cost of approximately \$1.5 billion, and the execution of power purchase agreements for up to 250 MW of PV projects to be developed by independent power producers.

OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies including; tax matters, Chapter 11 disputed claims, and environmental matters, which are discussed in Notes 10, 15, and 17 of the Notes to the Consolidated Financial Statements.

REGULATORY MATTERS

The Utility is subject to substantial regulation. Set forth below are matters pending before the CPUC, the FERC, and the Nuclear Regulatory Commission ("NRC"), the resolutions of which may affect the Utility's and PG&E Corporation's results of operations or financial condition.

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay ("Humboldt Bay Unit 3"). The DOE failed to develop a permanent storage site by January 31, 1998. The Utility believes that the existing spent fuel pools at Diablo Canyon (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2.

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit ("Ninth Circuit") issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility.

In October 2008, the NRC rejected the final contention that had been made during the appeal. The appellant has filed a petition for review of the NRC's order in the Ninth Circuit. Although the appellant did not seek to obtain an order prohibiting the Utility from loading spent fuel, the petition stated that they may seek a stay of fuel loading at the facility. On December 31, 2008, the appellate court granted the Utility's request to intervene in the proceeding. All briefs by all parties are scheduled to be filed by April 8, 2009.

The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage is expected to begin in June 2009. If the Utility is unable to begin loading spent nuclear fuel by October 2010 for Unit 1 or May 2011 for Unit 2 and if the Utility is otherwise unable to increase its on-site storage capacity, the Utility would have to curtail or halt operations until such time as additional safe storage for spent fuel is made available.

On August 7, 2008, the U.S. Court of Appeals for the Federal Circuit issued an appellate order in the litigation pending against the DOE in which the Utility and other nuclear power plant owners seek to recover costs they incurred to build on-site spent nuclear fuel storage facilities due to the DOE's delay in constructing a national repository for nuclear waste. In October 2006, the U.S. Court of Federal Claims found that the DOE had breached its contract with the Utility but awarded the Utility approximately \$43 million of the \$92 million incurred by the Utility through 2004. In ruling on the Utility's appeal, the U.S. Court of Appeals for the Federal Circuit reversed the lower court on issues relating to the calculation of damages and ordered the lower court to re-calculate the award. Although various motions by the DOE for reconsideration are still pending, the judge in the lower court conducted a status conference on January 15, 2009 and has scheduled another conference for July 9, 2009. The Utility expects the final award will be approximately \$91 million for costs incurred through 2004 and that the Utility will recover all of its costs incurred after 2004 to build on-site storage facilities. Amounts recovered from the DOE will be credited to customers through rates.

PG&E Corporation and the Utility are unable to predict the outcome of any rehearing petition.

Energy Efficiency Programs and Incentive Ratemaking

In 2007, the CPUC established an incentive ratemaking mechanism applicable to the California investor-owned utilities' implementation of their energy efficiency programs funded for the 2006-2008 and 2009-2011 program cycles. To earn incentives the utilities must (1) achieve at least 85% of the CPUC's overall energy savings goal over the three-year program cycle and (2) achieve at least 80% of the CPUC's individual kilowatt-hour (kWh), kilowatt (kW), and gas therm savings goals over the three-year program cycle. If the utilities achieve between 85% and 99% of the CPUC's overall savings goal, 9% of the verified net benefits (i.e., energy resource savings minus total energy efficiency program costs) will accrue to shareholders and 91% of the verified net benefits will accrue to customers. If the utilities achieve 100% or more of the CPUC's overall savings goal, then 12% of the total verified net benefits will accrue to shareholders and 88% will accrue to customers. If the utilities achieve less than 65% of any one of the individual metric savings goals (i.e., kWh, kW, or gas therm), then the utilities must reimburse customers based on the greater of (1) 5 cents per kWh, 45 cents per therm, and \$25 per kW for each kWh, therm, or kW unit below the 65% threshold, or (2) a dollar-for-dollar payback of negative net benefits, also known as a cost-effectiveness guarantee. The maximum amount of revenue that the Utility could earn, and the maximum amount that the Utility could be required to reimburse customers, over the 2006-2008 program cycle is \$180 million.

Under the existing incentive ratemaking mechanism, the utilities are required to submit two interim claims; the first claim is based on estimated performance achieved during the first and second years of the three-year period, and the second claim is based on estimated performance achieved over the entire three-year period. Estimated performance will be calculated based on the number and cost of energy efficiency measures installed by the utilities and estimates and assumptions about the energy savings per energy efficiency measure.

On December 18, 2008, based on the Utility's first interim claim, the CPUC awarded the Utility \$41.5 million in shareholder incentive revenues for the Utility's energy efficiency program performance in 2006-2007. The awarded amount represents 35% of \$119 million in estimated shareholder incentive revenues for the 2006-2007 program years. The CPUC ruled that 65% of the incentives calculated for the utilities' 2006-2007 interim claims will be "held back" until completion of final measurement studies and a final verification report for the entire three-year program cycle. As long as the final measured energy savings are at least 65% of each of the CPUC's individual savings goals over the 2006-2008 program cycle, the utilities will not be required to pay back any incentives received on an interim basis. The CPUC also ruled that the utilities will not be entitled to any additional incentives for the 2006-2008 program period beyond the incentives already received if the utility's performance falls within a "deadband"; i.e., if a utility achieves (1) less than 80% of the CPUC's goal for any individual savings metric or (2) less than 85% of the CPUC's overall energy savings goal but greater than 65% of the CPUC's goal for each individual savings metric. On February 2, 2009 The Utility Reform Network and the CPUC's Division of Ratepayer Advocates filed an application for rehearing of the CPUC's December 18, 2008 award.

On January 29, 2009, the CPUC instituted a new proceeding to modify the existing incentive ratemaking mechanism, to adopt a new framework to review the utilities' 2008 energy efficiency performance, and to conduct a final review of the utilities' performance over the 2006-2008 program period. The CPUC also plans to develop a long-term incentive mechanism for program periods beginning in 2009 and beyond.

The utilities are required to submit their 2008 performance reports to the CPUC by February 28, 2009. The CPUC has stated it intends to adopt a new framework to examine these reports so as to allow any interim awards (or obligations) attributable to 2008 performance to be made (or imposed) no later than December 2009, and to allow any final awards (or obligations) attributable to performance over the 2006-2008 period to be made (or imposed) no later than December 2010.

Whether the Utility will receive all or a portion of the remaining \$77 million in incentives for the 2006-2007 program years, whether the Utility will receive any additional incentives or incur a reimbursement obligation in 2009 based on the second interim claim, and whether the final true-up in 2010 will result in a positive or negative adjustment, depends on the new framework and rules to be adopted by the CPUC.

The Utility intends to file an amended application on March 2, 2009 to seek CPUC approval of the Utility's 2009-2011 energy efficiency programs and funding authorization of approximately \$1.8 billion over the three-year cycle, an approximate increase of \$860 million over the 2006-2008 budget. The CPUC has authorized bridge funding of approximately \$33 million per month to allow the Utility to continue existing energy efficiency programs into 2009 until the CPUC issues a final order on the 2009-2011 application.

Application to Recover Hydroelectric Generation Facility Divestiture Costs

On April 14, 2008, the Utility filed an application with the CPUC requesting authorization to recover approximately \$47 million, including \$12.2 million of interest, of the costs it incurred in connection with the Utility's efforts to determine the market value of its hydroelectric generation facilities in 2000 and 2001. These efforts were undertaken at the direction of the CPUC in preparation for the proposed divestiture of the facilities to further the development of a competitive generation market in California. The Utility continues to own its hydroelectric generation assets. On February 18, 2009, a proposed decision was issued by the administrative law judge, which if adopted by the CPUC, would allow the Utility to recover these costs. It is expected that the CPUC will issue a final decision in 2009.

Electric Transmission Owner Rate Cases

On October 22, 2008, the FERC approved an all-party settlement in the Utility's TO rate case that was filed in July 2007. The settlement sets an annual wholesale base transmission revenue requirement of \$706 million and a retail base transmission revenue requirement of \$718 million, effective March 1, 2008. The Utility has been reserving the difference between expected revenues based on rates requested by the Utility in its TO rate application and expected revenues based on rates proposed in the settlement. As a result, the settlement will not impact the Utility's results of operations or financial condition. The Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2010.

Also, on September 30, 2008, the FERC accepted the Utility's TO rate case that was filed on July 30, 2008 requesting an increase in retail base revenue requirement to \$849 million, and an increase in the Utility's wholesale base revenue requirement to \$838 million. As it has in the past, the FERC suspended the rate increase associated with the requested increase in revenue requirements for five months, until March 1, 2009. The increase in rates will be subject to refund pending final FERC approval of the requested increase in revenue requirements. The Utility, members of the FERC's staff, and interveners, have been engaged in settlement discussions. Any settlement that is reached would be subject to the FERC's approval. If the parties are not able to reach a settlement, the FERC would hold hearings before issuing a decision on the Utility's request.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and storage, other goods and services, and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk. The Utility is also exposed to credit risk; the risk that counterparties fail to perform their contractual obligations.

As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs are recoverable through the ratemaking mechanism described below, fluctuations in electricity prices will not affect earnings but may impact cash flows. The Utility's natural gas procurement costs for its core customers are recoverable through the Core Procurement Incentive Mechanism ("CPIM") and other ratemaking mechanisms, as described below. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism. However, the Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk. Movement in interest rates can also cause earnings and cash flow to fluctuate.

The Utility actively manages market risks through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments, such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

The Utility estimates the fair value of derivative instruments using the midpoint of quoted bid and asked forward prices, including quotes from brokers and electronic exchanges, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

The Utility conducts business with wholesale customers and counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty failed to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices. Credit-related losses attributable to receivables and electric and gas procurement activities from wholesale customers and counterparties are expected to be recoverable from customers through rates and are not expected to have a material impact on net income.

Price Risk

Electricity Procurement

The Utility relies on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts, and its own electricity generation facilities. When customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. In order to satisfy the short position, the Utility purchases electricity from suppliers prior to the hour- and day-ahead CAISO scheduling timeframes, or in the real-time market. When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position. When the Utility is in a long position, the Utility sells the excess supply in the real-time market. The CAISO currently administers a real-time wholesale market for the sale of electric energy. This market is used by the CAISO to fine tune the balance of supply and demand in real time.

Price risk is associated with the uncertainty of prices when buying or selling to reduce open positions (short or long positions). This price risk is mitigated by electricity price caps. The FERC has adopted a "soft" cap on energy prices of \$400 per MWh that applies to the spot market (i.e., real-time, hour-ahead and day-ahead markets) throughout the WECC area. (A "soft" cap allows market participants to submit bids that exceed the bid cap if adequately justified, but does not allow such bids to set the market clearing price. A "hard" cap prohibits bids that exceed the cap, regardless of the seller's costs.)

As part of the CAISO's Market Redesign and Technology Upgrade ("MRTU") initiative, the CAISO plans to implement a change to the day-ahead, hour-ahead and real-time markets including new offer price "hard" caps of \$500/MWh when MRTU begins, rising to \$750/MWh after the twelfth month of MRTU, and finally to \$1,000/MWh after the twenty-fourth month. The CAISO has also filed tariff amendments pending approval with the FERC stating that for settlements purposes, all prices shall not exceed \$2,500/MWh and shall not be less than negative \$2,500/MWh during the first twelve months of operation. After delaying the MRTU start date several times, the CAISO has stated that the start date will be April 1, 2009.

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts, or DWR contracts allocated to the Utility's customers, is subject to change for a number of reasons, including:

- periodic expirations or terminations of existing electricity purchase contracts including the DWR's contracts;
- the execution of new electricity purchase contracts;
- fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- changes in the Utility's customers' electricity demands due to customer and economic growth or decline, weather, implementation of new energy efficiency and demand response programs, direct access, and community choice aggregation;
- the acquisition, retirement or closure of generation facilities; and
- changes in market prices that make it more economical to purchase power in the market rather than use the Utility's existing resources.

Lengthy, unexpected outages of the Utility's generation facilities or other facilities from which it purchases electricity also could cause the Utility to be in a short position. It is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010, if suitable storage facilities are not available for spent nuclear fuel, which would cause a significant increase in the Utility's short position (see "Spent Nuclear Fuel Storage Proceedings" above). If any of the above events were to occur, the Utility may find it necessary to procure electricity from third parties at then-current market prices.

In December 2007, the DWR terminated a contract with Calpine Corporation to purchase 1,000 MW of base load power needed by the Utility's customers and replaced it with a 180 MW tolling arrangement. In addition, the DWR may try to terminate or renegotiate other long-term power purchase contracts it has entered into with other power suppliers. To the extent DWR does terminate or renegotiate other contracts, the Utility will be responsible for procuring additional electricity to meet its customers' demand, potentially at then-current market prices.

The Utility expects to satisfy at least some of the forecasted short position through the CPUC-approved contracts it has entered into in accordance with its CPUC-approved long-term procurement plan covering 2007 through 2016. The Utility recovers the costs incurred under these contracts and other electricity procurement costs through retail electricity rates that are adjusted whenever the forecasted aggregate over-collections or under-collections of the Utility's procurement costs for the current year exceed 5% of the Utility's prior year electricity procurement revenues. The Chapter 11 Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. As long as these cost recovery mechanisms remain in place, adverse market price changes are not expected to impact the Utility's net income. The Utility is at risk to the extent that the CPUC may in the future disallow portions or the full costs of procurement transactions. Additionally, market price changes could impact the timing of the Utility's cash flows.

Electric Transmission Congestion Rights

Among other features, the CAISO's MRTU initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including load serving entities, taking energy that passes between those locations. The CAISO also will provide Congestion Revenue Rights ("CRRs") to allow market participants, including load serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes both an allocation phase (in which load serving entities receive CRRs at no cost) and an auction phase (priced at market, and available to all market participants).

The Utility has been allocated and has acquired via auction certain CRRs as of December 31, 2008, and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date, to be used when MRTU becomes effective. During 2008, the Utility participated in an auction to acquire additional firm electricity transmission rights ("FTRs") in order to hedge its physical and financial risk until the MRTU becomes effective. The CAISO has delayed the start date of MRTU several times, but is now targeting April 1, 2009.

Natural Gas Procurement (Electric Portfolio)

A portion of the Utility's electric portfolio is exposed to natural gas price risk. The Utility manages this risk in accordance with its risk management strategies included in electricity procurement plans approved by the CPUC. The CPUC did not approve the Utility's proposed electric portfolio gas hedging plan that was included in the Utility's long-term procurement plan. Instead, the CPUC deferred consideration of the proposal to another proceeding. The CPUC ordered the Utility to continue operating under the previously approved gas hedging plan. The expenses associated with the hedging plan are expected to be recovered through rates.

Natural Gas Procurement (Core Customers)

The Utility generally enters into physical and financial natural gas commodity contracts from one to twelve months in length to fulfill the needs of its retail core customers. Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of gas may be purchased in the monthly and, to a lesser extent, daily spot market to meet such seasonal demand. The Utility's cost of natural gas purchased for its core customers includes costs for the commodity, Canadian and interstate transportation, and intrastate gas transmission and storage.

Under the CPIM, the Utility's 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 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 shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or \$25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

For the CPIM period ending October 31, 2008, the CPUC will audit the results of the Utility's CPIM performance. Subject to the audit results, a shareholder award may be recorded during 2009. For the CPIM period ending October 31, 2007, the Utility earned a shareholder award of \$10.1 million, which was recorded in the second quarter of 2008. The CPUC will audit the results of the Utility's CPIM performance ending October 31, 2008. Subject to the audit results, a shareholder award may be recorded during 2009.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from 1 to 16 years. These long-term nuclear fuel agreements are with large, well-established international producers in order to diversify its commitments and provide security of supply. Nuclear fuel costs are recovered from customers through rates and, therefore, changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas Transportation and Storage

The Utility uses value-at-risk to measure the shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available, the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including, but not limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies that may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately \$16 million at December 31, 2008. The Utility's high, low, and average values-at-risk during the twelve months ended December 31, 2008 were approximately \$34 million, \$16 million, and \$25 million, respectively.

Convertible Subordinated Notes

At December 31, 2008, PG&E Corporation had outstanding approximately \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,059 shares of PG&E Corporation common stock, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment for significant changes in the number of outstanding shares of PG&E Corporation's common stock. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. During 2008, PG&E Corporation paid approximately \$28 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. On January 15, 2009, PG&E Corporation paid approximately \$7 million of "pass-through dividends."

On January 13, 2009, PG&E Corporation, upon request by an investor, converted \$28 million of Convertible Subordinated Notes into 1,855,865 shares at the conversion price of \$15.09 per share. Total outstanding Convertible Subordinated Notes after the conversion is approximately \$252 million.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), the dividend participation rights of the Convertible Subordinated Notes are considered to be embedded derivative instruments and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. The payment of pass-through dividends is recognized as an operating cash flow in PG&E Corporation's Consolidated Statements of Cash Flows. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (in Other income (expense), net). At December 31, 2008 and December 31, 2007, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$42 million and \$62 million, respectively, of which \$28 million and \$25 million, respectively, was classified as a current liability (in Current Liabilities - Other) and \$14 million and \$37 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other) in the accompanying Consolidated Balance Sheets. The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157 "Fair Value Measurements" ("SFAS No. 157"), resulting in a \$6 million increase in the liability. (See Note 12 of the Notes to the Consolidated Financial Statements for further discussion of the implementation of SFAS No. 157.)

Interest Rate Risk

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2008, if interest rates changed by 1% for all current variable rate debt issued by PG&E Corporation and the Utility, the change would affect net income for the twelve months ended December 31, 2008 by approximately \$0.1 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

Credit Risk

The Utility manages credit risk associated with its wholesale customers and counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically and a detailed credit analysis is performed at least annually. The Utility ties many energy contracts to master agreements that require security (referred to as “credit collateral”) in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility's net credit risk exposure to its wholesale customers and counterparties, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at December 31, 2008 and December 31, 2007:

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
December 31, 2008	\$ 240	\$ 84	\$ 156	2	\$ 107
December 31, 2007	\$ 311	\$ 91	\$ 220	2	\$ 111

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

⁽²⁾ Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

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

Regulatory Assets and Liabilities

The Utility accounts for the financial effects of regulation in accordance with SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation” (“SFAS No. 71”). SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are being recovered through current rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities. Regulatory assets and liabilities are recorded when it is probable, as defined in SFAS No. 5, “Accounting for Contingencies” (“SFAS No. 5”), that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court appeals. The Utility also maintains regulatory balancing accounts, which are comprised of sales and cost balancing accounts. These balancing accounts are used to record the differences between revenues and costs that can be recovered through rates.

If the Utility determined that it could not apply SFAS No. 71 to its operations or, if under SFAS No. 71, it could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At December 31, 2008, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$7.2 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$4.4 billion.

Environmental Remediation Liabilities

Given the complexities of the legal and regulatory environment in which the environmental laws operate, the process of estimating environmental remediation liabilities is subjective. The Utility records a liability associated with environmental remediation activities when it is determined that remediation is probable, as defined in SFAS No. 5, and the cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At December 31, 2008, the Utility's accrual for undiscounted and gross environmental liabilities was approximately \$568 million. The accrual for undiscounted and gross environmental liabilities is representative of future events that are probable. In determining maximum undiscounted future costs, events that are reasonably possible but not probable are included in the estimation. The Utility's undiscounted future costs could increase to as much as \$944 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

Asset Retirement Obligations

The Utility accounts for its long-lived assets under SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"), and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations - An Interpretation of SFAS No. 143" ("FIN 47"). SFAS No. 143 and FIN 47 require that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and FIN 47 and costs recovered through the ratemaking process.

The fair value of asset retirement obligations ("ARO") is dependent upon the following components:

- *Decommissioning costs* - The estimated costs for labor, equipment, material, and other disposal costs;
- *Inflation adjustment* - The estimated cash flows are adjusted for inflation estimates;
- *Discount rate* - The fair value of the obligation is based on a credit-adjusted risk free rate that reflects the risk associated with the obligation; and
- *Third-party mark-up adjustments* - Internal labor costs included in the cash flow calculation were adjusted for costs that a third party would incur in performing the tasks necessary to retire the asset in accordance with SFAS No. 143.
- *Estimated date of decommissioning* - The fair value of the obligation will change based on the expected date of decommissioning.

Changes in these factors could materially affect the obligation recorded to reflect the ultimate cost associated with retiring the assets under SFAS No. 143 and FIN 47. For example, a premature shutdown of the nuclear facilities at Diablo Canyon would increase the likelihood of an earlier start to decommissioning and cause an increase in the obligation. (See Note 13 of the Notes to the Consolidated Financial Statements and "Capital Expenditures" and "Results of Operations" above.) Additionally, if the inflation adjustment increased 25 basis points, this would increase the balance for ARO by approximately 0.81%. Similarly, an increase in the discount rate by 25 basis points would decrease ARO by 0.57%. At December 31, 2008, the Utility's estimated cost of retiring these assets is approximately \$1.7 billion.

Accounting for Income Taxes

PG&E Corporation and the Utility account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes," and FIN 48, which requires judgment regarding the potential tax effects of various transactions and ongoing operations to determine obligations owed to tax authorities. (See Note 10 of the Notes to the Consolidated Financial Statements.) Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates of the timing and probability of recognition of income and deductions. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in tax laws, PG&E Corporation's financial condition in future periods, and the final review of filed tax returns by taxing authorities.

Pension and Other Postretirement Plans

Certain employees and retirees of PG&E Corporation and its subsidiaries participate in qualified and non-qualified non-contributory defined benefit pension plans. Certain retired employees and their eligible dependents of PG&E Corporation and its subsidiaries also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as “other postretirement benefits”). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans” (“SFAS No. 158”), SFAS No. 87, “Employers’ Accounting for Pensions” (“SFAS No. 87”) and other benefits under SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other than Pensions” (“SFAS No. 106”) are based on a variety of factors. These factors include the provisions of the plans, employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions utilized, PG&E Corporation's and the Utility's estimate of these costs and obligations is a critical accounting estimate.

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

In accordance with accounting rules, changes in benefit obligations associated with these assumptions may not be recognized as costs on the income statement. Differences between actuarial assumptions and actual plan results are deferred in Accumulated other comprehensive income (loss) and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market value of the related plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. As such, benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. PG&E Corporation's and the Utility's recorded pension expense totaled \$169 million in 2008, \$117 million in 2007, and \$185 million in 2006 in accordance with the provisions of SFAS No. 87. PG&E Corporation and the Utility's recorded expense for other postretirement benefits totaled \$44 million in 2008, \$44 million in 2007, and \$49 million in 2006 in accordance with the provisions of SFAS No. 106.

As of December 31, 2006, PG&E Corporation and the Utility adopted SFAS No. 158, which requires the funded status of an entity's plans to be recognized on the balance sheet with an offsetting entry to Accumulated other comprehensive income (loss), resulting in no impact to the statement of income.

Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other postretirement benefits based on the lesser of the SFAS No. 106 expense or the annual tax-deductible contributions to the appropriate trusts.

PG&E Corporation's and the Utility's funding policy is to contribute tax-deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility has not identified any minimum funding requirements related to its pension plans.

In July 2006, the CPUC approved the Utility's request to resume rate recovery for the Utility's contributions to the qualified defined benefit pension plan for the years 2006 through 2009, with the goal of fully-funded status by 2010. In March 2007, the CPUC extended the terms of the decision for one additional year, through 2010. PG&E Corporation and the Utility made total pension contributions of approximately \$139 million in 2007 and \$182 million in 2008, and expect to make total contributions of approximately \$176 million annually for the years 2009 and 2010. PG&E Corporation and the Utility made total contributions of approximately \$38 million in 2007 and \$48 million in 2008 related to their other postretirement benefit plans and expect to make contributions of approximately \$58 million annually for the years 2009 and 2010.

Pension and other postretirement benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and other postretirement benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S. equities, absolute return securities, and fixed income securities. Investment securities are exposed to various risks, including interest rate risk, credit risk, and overall market volatility. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other postretirement benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets.

Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 7.3% compares to a ten-year actual return of 4.6%.

The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from market data of approximately 300 Aa-grade non-callable bonds at December 31, 2008. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other postretirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

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

(in millions)	Increase (decrease) in Assumption	Increase in 2008 Pension Costs	Increase in Projected Benefit Obligation at December 31, 2008
Discount rate	(0.5)%	\$ 15	\$ 667
Rate of return on plan assets	(0.5)%	47	-
Rate of increase in compensation	0.5%	17	162

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

(in millions)	Increase (decrease) in Assumption	Increase in 2008 Other Postretirement Benefit Costs	Increase in Accumulated Benefit Obligation at December 31, 2008
Health care cost trend rate	0.5%	\$ 6	\$ 33
Discount rate	(0.5)%	6	75

NEW ACCOUNTING POLICIES

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157. SFAS No. 157 establishes a fair value hierarchy that prioritizes inputs to valuation techniques used to measure the fair value of an asset or liability. The objective of a fair value measurement is to determine the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the “exit price.” The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. (See Notes 2 and 12 of the Notes to the Consolidated Financial Statements for further discussion on SFAS No. 157.)

Level 3 Instruments at Fair Value

As Level 3 measurements are based on unobservable inputs, significant judgment may be used in the valuation of these instruments. Accordingly, the following table sets forth the fair values of instruments classified as Level 3 within the fair value hierarchy, along with a description of the valuation technique for each type of instrument:

(in millions)	Value as of	
	December 31, 2008	January 1, 2008
Money market investments (held by PG&E Corporation)	\$ 12	\$ -
Nuclear decommissioning trusts	5	8
Price risk management instruments	(156)	115
Long term disability trust	78	87
Dividend participation rights	(42)	(68)
Other	(2)	(4)
Total Level 3 Instruments	\$ (105)	\$ 138

Level 3 fair value measurements represent approximately 5% of the total net value of all fair value measurements of PG&E Corporation. During the twelve months ended December 31, 2008, there were no material increases or decreases in Level 3 assets or liabilities resulting from a transfer of assets or liabilities from, or into, Level 1 or Level 2. The majority of these instruments are accounted for in accordance with SFAS No. 71, as amended, as they are expected to be recovered or refunded through regulated rates. Therefore, changes in the aggregate fair value of these assets and liabilities (including realized and unrealized gains and losses) are recorded within regulatory accounts in the accompanying Consolidated Balance Sheets with the exception of the dividend participation rights associated with PG&E Corporation's Convertible Subordinated Notes. The changes in the fair value of the dividend participation rights are reflected in Other income (expense), net in PG&E Corporation's Consolidated Statements of Income. Changes in the fair value of the Level 3 instruments did not have a material effect on liquidity and capital resources as of December 31, 2008.

Money Market Investments

PG&E Corporation invests in AAA-rated money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued based on observable inputs such as expected yield and credit quality and are thus classified as Level 1 instruments. Approximately \$164 million held in money market funds are recorded as Cash and cash equivalents in PG&E Corporation's Consolidated Balance Sheets.

As of December 31, 2008, PG&E Corporation classified approximately \$12 million invested in one money market fund as a Level 3 instrument because the fund manager imposed restrictions on fund participants' redemption requests. PG&E Corporation's investment in this money market fund, previously recorded as Cash and cash equivalents, is recorded as Prepaid expenses and other in PG&E Corporation's Consolidated Balance Sheets.

Nuclear Decommissioning Trusts and Long Term-Disability Trust

The nuclear decommissioning trusts and the long-term disability trust primarily hold equities, debt securities, mutual funds, and life insurance policies. These instruments are generally valued based on unadjusted prices in active markets for identical transactions or unadjusted prices in active markets for similar transactions. The nuclear decommissioning trusts and the long-term disability trust also invest in long-term commingled funds, which are funds that consist of assets from several accounts that are intermingled. These commingled funds have liquidity restrictions and lack an active market for individual shares of the funds; therefore the trusts' investments in these funds are classified as Level 3. The Level 3 nuclear decommissioning trust assets decreased from approximately \$8 million at January 1, 2008 to approximately \$5 million at December 31, 2008. The decrease of approximately \$3 million for the twelve months ended December 31, 2008 was primarily due to unrealized losses of these commingled fund investments. The Level 3 long-term disability trust assets decreased from approximately \$87 million at January 1, 2008 to approximately \$78 million at December 31, 2008. This decrease of approximately \$9 million for the twelve months ended December 31, 2008 was primarily due to net purchases and unrealized losses on these commingled fund investments.

Price Risk Management Instruments

The price risk management instrument category is comprised of physical and financial derivative contracts including futures, forwards, options, and swaps that are both exchange-traded and over-the-counter ("OTC") traded contracts. PG&E Corporation and the Utility apply consistent valuation methodology to similar instruments. Since the Utility's contracts are used within the regulatory framework, regulatory accounts are recorded to offset the associated gains and losses of these derivatives, which will be reflected in future rates. The Level 3 price risk management instruments decreased from an asset of approximately \$115 million as of January 1, 2008 to a liability of approximately \$156 million as of December 31, 2008. This decrease of approximately \$271 million was primarily due to a reduction in commodity prices.

Type of Instrument	Value (in millions)	
	December 31, 2008	January 1, 2008
Options (exchange-traded and OTC)	\$ 28	\$ 50
Congestion revenue rights, Firm transmission rights, and Demand response contracts	99	61
Swaps and forwards	(366)	(2)
Netting and collateral	83	6
Total	<u>\$ (156)</u>	<u>\$ 115</u>

All options (exchange-traded and OTC) are valued using the Black's Option Pricing Model and classified as Level 3 measurements primarily due to volatility inputs. The Utility receives implied volatility for options traded on exchanges which may be adjusted to incorporate the specific terms of the Utility's contracts, such as strike price or location.

CRRs allow market participants, including load serving entities, to hedge financial risk of CAISO-imposed congestion charges in the day-ahead market to be established when MRTU becomes effective. FTRs allow market participants, including load serving entities to hedge both the physical and financial risk associated with CAISO-imposed congestion charges until the MRTU becomes effective. The Utility's demand response contracts with third party aggregators of retail electricity customers contain a call option entitling the Utility to require that the aggregator reduce electric usage by the aggregators' customers at times of peak energy demand or in response to a CAISO alert or other emergency. As the markets for CRRs, FTRs, and demand response contracts have minimal activity, observable inputs may not be available in pricing these instruments. Therefore, the pricing models used to value these instruments often incorporate significant estimates and assumptions that market participants would use in pricing the instrument. Accordingly, they are classified as Level 3 measurements. When available, observable market data is used to calibrate pricing models.

The remaining Level 3 price risk management instruments are OTC derivative instruments that are valued using pricing models based on the net present value of estimated future cash flows based on broker quotations. The Utility receives multiple non-binding broker quotes for certain locations which are generally averaged for valuation purposes. In certain circumstances, broker quotes may be interpolated or extrapolated to fit the terms of a contract, such as frequency of settlement or tenor. These instruments are classified within Level 3 of the fair value hierarchy.

Dividend Participation Rights

The dividend participation rights of the Convertible Subordinated Notes are embedded derivative instruments in accordance with SFAS No. 133 and, therefore, are bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Balance Sheets. The dividend participation rights are valued based on the net present value of estimated future cash flows using internal estimates of common stock dividends. These rights are recorded as Current Liabilities-Other and Noncurrent Liabilities-Other in PG&E Corporation's Consolidated Balance Sheets. (See Note 4 of the Notes to the Consolidated Financial Statements for further discussion of these instruments.)

Nonperformance Risk

In accordance with SFAS No. 157, PG&E Corporation and the Utility incorporate the risk of nonperformance into the valuation of their fair value measurements. Nonperformance risk adjustments on the Utility's price risk management instruments are based on current market inputs when available, such as credit default swaps spreads. When such information is not available, internal models may be used. The nonperformance risk adjustment for the net price risk management instruments contributed less than 5% of the value on December 31, 2008. As the Utility's contracts are used within the regulatory framework, the nonperformance risk adjustments are recorded to regulatory accounts and do not impact earnings.

See Note 12 of the Notes to the Consolidated Financial Statements for further discussion on fair value measurements.

Amendment of FASB Interpretation No. 39

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of FASB Staff Position on FASB Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"). Under FIN 39-1, a reporting entity is required to offset the cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement when reporting those amounts on a net basis. The provisions of FIN 39-1 are applied retrospectively. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion and financial statement impact of the implementation of FIN 39-1.

Fair Value Option

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value with changes in fair value recognized in earnings. PG&E Corporation and the Utility have not elected the fair value option for any assets or liabilities as of and during the three and twelve months ended December 31, 2008; therefore, the adoption of SFAS No. 159 did not impact the Condensed Consolidated Financial Statements.

Disclosure by Public Entities (Enterprises) about Transfers of Financial Asset and Interests in Variable Interest Entities

On December 31, 2008, PG&E Corporation and the Utility adopted the provisions of FASB Staff Position ("FSP") FAS 140-4 and FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" ("FSP FAS 140-4 and FIN 46R-8"). This FSP amends FASB No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities" to require public companies to provide additional qualitative disclosures about transfers of financial assets. This guidance also amended FIN 46R to require public enterprises to provide additional disclosures about their involvement with variable interest entities ("VIEs") when they are the primary beneficiary of the VIE, hold a significant variable interest in the VIE, or are sponsors of and hold a variable interest in the VIE.

Although PG&E Corporation and Utility were not impacted by the amendment to FASB No. 140 as of December 31, 2008, they were impacted by the amendment to FIN 46R, primarily through the Utility's power purchase agreements which may be considered significant variable interests. Accordingly, when the Utility has a significant variable interest in a VIE, FSP FAS 140-4 and FIN 46R-8 require additional disclosures about the entity, the extent of the Utility's involvement with the entity, and the Utility's methodology for evaluating these entities under FIN 46R. See "Consolidation of Variable Interest Entities" within Note 2 to the Consolidated Financial Statements for expanded disclosures required by FSP FAS 140-4 and FIN 46R-8.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133

In March 2008, the FASB issued SFAS No. 161, “Disclosures about Derivative Instruments and Hedging Activities-an amendment of FASB Statement No. 133” (“SFAS No. 161”). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133. An entity is required to provide qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures on fair value amounts of, and gains, and losses on derivative instruments, and disclosures relating to credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. PG&E Corporation and the Utility will include the expanded disclosure required by SFAS No. 161 in their combined quarterly report on Form 10-Q for the quarter ended March 31, 2009.

Disclosures about Employers’ Postretirement Benefit Plan Asset - an amendment to FASB Statement No. 132(R)

In December 2008, the FASB issued FSP FAS 132(R)-1, “Employers’ Disclosures about Postretirement Benefit Plan Assets” (“FSP 132(R)-1”). FSP 132(R)-1 amends and expands the disclosure requirements of SFAS No. 132. An entity is required to provide qualitative disclosures about how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, and the concentration of risk within plan assets. Additionally, quantitative disclosures are required showing the fair value of each major category of plan assets, the levels in which each asset is classified within the fair value hierarchy, and a reconciliation for the period of plan assets which are measured using significant unobservable inputs. FSP 132(R)-1 is effective prospectively for fiscal years ending after December 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP 132(R)-1.

Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement - an amendment to FASB Statement No. 107 and FASB Statement No. 133

In September 2008, the FASB issued Emerging Issues Task Force (“EITF”) 08-5, “Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement” (“EITF 08-5”). EITF 08-5 clarifies the unit of account in determining the fair value of a liability under SFAS No. 107 “Disclosures about Fair Value of Financial Instruments” or SFAS No. 133 “Accounting for Derivatives and Hedging Activities”. Specifically, it requires an entity to incorporate any third-party credit enhancements that are issued with and are inseparable from a debt instrument into the fair value of that debt instrument. EITF 08-5 is effective prospectively for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. PG&E Corporation and the Utility are currently evaluating the impact of EITF 08-5.

Equity Method Investment Accounting Consideration - an amendment to Accounting Principles Board No. 18

In November 2008, the FASB issued EITF 08-6, “Equity Method Accounting Considerations” (“EITF 08-6”). EITF 08-6 clarifies the application of equity method accounting under Accounting Principles Board 18, “The Equity Method of Accounting for Investments in Common Stock”. Specifically, it requires companies to initially record equity method investments based on the cost accumulation model, precludes separate other-than-temporary impairment tests on an equity method investee’s indefinite-lived assets from the investee’s test, requires companies to account for an investee’s issuance of shares as if the equity method investor had sold a proportionate share of its investment, and requires that an equity method investor continue to apply the guidance in paragraph 19(l) of Opinion 18 upon a change in the investor’s accounting from the equity method to the cost method. EITF 08-6 is effective prospectively for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. PG&E Corporation and the Utility are currently evaluating the impact of EITF 08-6.

TAX MATTERS

During the fourth quarter of 2008, PG&E Corporation and the IRS finalized the settlement of the IRS’ audits of PG&E Corporation’s consolidated tax returns for tax years 2001 through 2004. As a result of the settlement, PG&E Corporation recognized after-tax income of approximately \$257 million, including interest, in the fourth quarter of 2008. Approximately \$154 million of this amount related to NEGTEC, PG&E Corporation’s former subsidiary, and was recorded as income from discontinued operations. Approximately \$60 million of the \$257 million in net income relates to the Utility. PG&E Corporation expects to receive a tax refund from the IRS of approximately \$310 million, plus interest, as a result of the settlement, of which approximately \$170 million will be allocated to the Utility.

Also, on January 30, 2009, PG&E Corporation reached a tentative agreement with the IRS to resolve refund claims related to the 1998 and 1999 tax years that, if approved by the U.S. Congress’ Joint Committee on Taxation (“Joint Committee”), would result in a cash refund of approximately \$200 million, plus interest, to be allocated completely to the Utility. The Joint Committee’s decision is currently expected in the second quarter of 2009, and if approved, PG&E Corporation expects to receive the refund by 2009 year end. See Note 10 of the Notes to the Consolidated Financial Statements for discussion of tax matters.

ENVIRONMENTAL MATTERS

The Utility’s operations are subject to extensive federal, state, and local environmental laws and permits. (See “Risk Factors” below.) The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site. See “Critical Accounting Policies” above and Note 17 of the Notes to the Consolidated Financial Statements for a discussion of estimated environmental remediation liabilities.

In addition, there is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require 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. Depending on the form of the final federal or state regulations that may ultimately be adopted, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the final federal or state regulations require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. See Note 17 of the Notes to the Consolidated Financial Statements for more information.

LEGAL MATTERS

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 17 of the Notes to the Consolidated Financial Statements for a discussion of the accrued liability for legal matters.

RISK FACTORS

Risks Related to PG&E Corporation

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

PG&E Corporation is a holding company with no revenue generating operations of its own. PG&E Corporation's ability to pay interest on its \$280 million of convertible subordinated notes, and to pay dividends on its common stock, as well as satisfy its other financial obligations, primarily depends on the earnings and cash flows of the Utility and the ability of the Utility to distribute cash to PG&E Corporation (in the form of dividends and share repurchases) and reimburse PG&E Corporation for the Utility's share of applicable expenses. Before it can distribute cash to PG&E Corporation, the Utility must use its resources to satisfy its own obligations, including its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, and meet its obligations to employees and creditors. If the Utility is not able to make distributions to PG&E Corporation or to reimburse PG&E Corporation, PG&E Corporation's ability to meet its own obligations could be impaired and its ability to pay dividends could be restricted.

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

The CPUC imposed certain conditions when it approved the original formation of a holding company for the Utility, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC later issued decisions adopting an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve." The CPUC's interpretation of PG&E Corporation's obligation under the first priority condition could require PG&E Corporation to infuse the Utility with significant capital in the future, or could prevent distributions from the Utility to PG&E Corporation, either of which could materially restrict PG&E Corporation's ability to pay or increase its common stock dividend, meet other obligations, or execute its business strategy.

Adverse resolution of pending litigation against PG&E Corporation involving PG&E Corporation's alleged violation of the CPUC's so-called "first priority condition" holding company conditions could have a material adverse effect on PG&E Corporation's financial condition, results of operations and cash flow.

In 2002, the California Attorney General and the City and County of San Francisco filed complaints against PG&E Corporation alleging that PG&E Corporation failed to provide adequate financial support to the Utility in 2000 and 2001 during the California energy crisis and wrongfully transferred funds from the Utility to PG&E Corporation during the period 1997 through 2000 (primarily in the form of dividends and stock repurchases), and from PG&E Corporation to other affiliates of PG&E Corporation, in violation of the first priority and other holding company conditions. The complaints claim these alleged violations constituted unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code. The plaintiffs seek restitution of amounts alleged to have been wrongly transferred, estimated by plaintiffs to be approximately \$5 billion, civil penalties of \$2,500 against each defendant for each violation of Section 17200, a total penalty of not less than \$500 million, and costs of suit, among other remedies. Adverse resolution of this pending litigation could have a material, adverse effect on PG&E Corporation's financial condition, results of operations and cash flows.

Risks Related to PG&E Corporation and the Utility

It is uncertain whether PG&E Corporation or the Utility will be able to successfully access the capital markets or finance planned capital expenditures on favorable terms or rates.

The Utility's ability to fund its operations, pay principal and interest on its debt, fund capital expenditures and provide collateral to support its natural gas and electricity procurement hedging contracts depends on the levels of its operating cash flow and access to the capital markets, in particular its ability to sell commercial paper and long-term unsecured debt. In addition, PG&E Corporation's ability to make planned investments in natural gas pipeline projects depends on the ability of the Utility to pay dividends to PG&E Corporation and PG&E Corporation's independent access to the capital markets. PG&E Corporation may also be required to access the capital markets when the Utility is successful in selling long-term debt so that it may make the equity contributions required to maintain the Utility's applicable equity ratio.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation. PG&E Corporation also would need to consider its alternatives, such as contributing capital to the Utility, to enable the Utility to fulfill its obligation to serve. If PG&E Corporation is required to contribute equity to the Utility, it would be required to secure these funds from the capital markets.

PG&E Corporation's and the Utility's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in their credit ratings, changes in the federal or state regulatory environment affecting energy companies, the overall health of the energy industry, volatility in electricity or natural gas prices, and general economic and market conditions.

The capital and credit markets have been experiencing extreme volatility and disruption for more than 12 months. The recent financial distress experienced at major financial institutions has caused significant disruption in the capital markets, particularly in the commercial paper markets where short-term interest rates have increased significantly, available maturities have shortened and access has generally contracted. Although the U.S. government has enacted legislation and created programs to help stabilize credit markets and financial institutions and restore liquidity, it is uncertain whether these programs individually or collectively will have beneficial effects in the credit markets or will reduce volatility or uncertainty in the financial markets.

The volume of utility bond issuances has decreased as a result of greater difficulty in issuing such bonds and the increase in the interest rate spread over Treasury bills for all such bonds. It may be more difficult or undesirable to issue new long-term debt. To the extent such conditions persist, the more significant the implications become for the Utility, including the potential that adequate capital is not available to fund the Utility's operations and planned capital expenditures. If the Utility is unable, in part or in whole, to fund its operations and planned capital expenditures there could be a material adverse effect on PG&E Corporation and the Utility's results of operations, cash flows and financial condition.

Market performance or changes in other assumptions could require PG&E Corporation and the Utility to make significant unplanned contributions to its pension, other post-retirement benefits plans, and nuclear decommissioning trusts.

PG&E Corporation and the Utility provide defined benefit pension plans and other post-retirement benefits for certain employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. Up to approximately 60% of the plan assets and trust assets have generally been invested in equity securities, which are subject to market fluctuation. A decline in the market value may increase the funding requirements for these plans and trusts.

The costs of providing pension and other post-retirement benefits is also affected by other factors, including the assumed rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, levels of assumed interest rates, future government regulation and prior contributions to the plans. Similarly, funding requirements for the nuclear decommissioning trusts are affected by changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements, changes in assumptions as to decommissioning dates, technology and costs of labor, materials and equipment change and assumed rate of return on plan assets. For example, changes in interest rates affect the liabilities under the plans as interest rates decrease, the liabilities increase, potentially increasing the funding requirements.

Primarily as a result of the 2008 performance of the equities market, at December 31, 2008, the funding status of the plans and nuclear decommissioning trusts are in an underfunded status. If the Utility is required to make significant unplanned contributions to fund the pension and post-retirement plans and nuclear decommissioning trusts and is unable to recover such contributions in rates, the contributions would negatively affect PG&E Corporation and the Utility's financial condition, cash flows and results of operations.

Other Utility obligations, such as its workers' compensation obligations, are not separately earmarked for recovery through rates. Therefore, increases in the Utility's workers' compensation liabilities and other unfunded liabilities caused by a decrease in the applicable discount rate negatively impact net income.

The Utility's revenues, operating results and financial condition may fluctuate with the economy and the economy's corresponding impact on the Utility's customers.

The Utility is impacted by the economic cycle of the customers it serves. The declining economy in the Utility's service territory and the declines in the values of residential real estate have resulted in lower customer demand and lower customer growth at the Utility, and an increase in unpaid customer accounts receivable. Increasing unemployment could further reduce demand as residential customers voluntarily reduce their consumption of electricity in response to decreases in their disposable income. A sustained downturn or sluggishness in the economy is further reflected in the Utility's sales to industrial and commercial customers. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller customer base increasing the potential that costs would be disallowed by regulators.

The completion of capital investment projects is subject to substantial risks and the rate at which the Utility invests and recovers capital will directly affect net income.

The Utility's ability to develop new generation facilities and to invest in its electric and gas systems is subject to many risks, including risks related to securing adequate and reasonably priced financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party contractors on which the Utility depends to develop these projects also face many of these risks, although their actions and responsiveness in the event of negative developments may be less within and in fact beyond the Utility's control. Changes in tax laws or policies, such as those relating to production and investment tax credits for renewable energy projects, may also affect when or whether the Utility develops a potential project. In addition, reduced forecasted demand for electricity and natural gas as a result of the slowing economy may also increase the risk that projects are deferred, abandoned or cancelled.

In addition, the Utility may incur costs that it will not be permitted to recover from customers. The Utility's amount and timing of capital expenditures can be affected by changes in the economy that impact customer demand and the rate of new customer connections. If capital spending in a particular time period is greater than assumed when rates were set, earnings could be negatively affected by an increase in depreciation, taxes and financing interest and the absence of authorized revenue requirements to recover a return on equity on the amount of capital expenses which exceeds assumed amounts. If capital spending in a particular time period is lower than assumed when rates were set, the Utility's rate base would be lower depriving the Utility of the opportunity to earn a return on equity on the delayed expenditures.

PG&E Corporation's investment in new natural gas pipelines projects is subject to similar risks, and, in the case of the proposed Pacific Connector, is subject to third parties' developing a proposed liquefied natural gas storage terminal. In addition, pipeline project development is conditioned on obtaining certain levels of capacity commitments from shippers. Many of these conditions must be satisfied by PG&E Corporation's investment partners.

PG&E Corporation's and the Utility's financial statements reflect various estimates, assumptions and values, and changes to these estimates, assumptions, and values, as well as the application of and changes in accounting rules, standards, policies, guidance, or interpretations could materially affect PG&E Corporation's and the Utility's financial condition or results of operations.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the disclosure of contingencies. (See the discussion under Note 1 of the Notes to the Consolidated Financial Statements and the section entitled "Critical Accounting Policies" in the MD&A.) If the information on which the estimates and assumptions are based prove to be incorrect or incomplete, if future events do not occur as anticipated, or if applicable accounting guidance, policies or interpretation change, management's estimates and assumptions will change as appropriate. A change in management's estimates or assumptions or the recognition of actual losses that differ from the amount of estimated losses, could have a material impact on PG&E Corporation and the Utility's financial condition and results of operations. For example, if management can no longer assume that potentially responsible parties will pay a material share of the costs of environmental remediation or if PG&E Corporation or the Utility incur losses in connection with environmental remediation, litigation or other legal, administrative or regulatory proceedings that materially exceed the provision it estimated for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations and cash flow would be materially adversely affected.

PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its costs in a timely manner from the Utility's customers through regulated rates and otherwise execute its business strategy.

The Utility is a regulated entity subject to CPUC and FERC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity and natural gas for its customers, issuance of securities, dispositions of utility assets and facilities, and aspects of the siting and operation of its electricity and natural gas operating assets. Executing the Utility's business strategy depends on periodic regulatory approvals related to these and other matters.

The Utility's financial condition particularly depends on its ability to recover in rates, in a timely manner, the costs of electricity and natural gas purchased for its customers, its operating expenses, and an adequate return of and on the capital invested in its utility assets, including the costs of long-term debt and equity issued to finance their acquisition. Unanticipated changes in operating expenses or capital expenditures can cause material differences between forecasted costs used to determine rates and actual costs incurred which, in turn, affect the Utility's ability to earn its authorized rate of return. The Utility's revenue requirements for its basic electric and natural gas distribution operations and its electric generation operations have been set by the CPUC through 2010. The Utility has been implementing various measures to improve operating efficiency and achieve sustainable cost-savings to offset increases in labor costs, to improve the safety and reliability of the electric and natural gas systems, to expand and maintain the electric and natural gas systems, technology infrastructure and support, and other increases in operating and maintenance costs. Since the Utility's next GRC will not be effective until January 1, 2011, the Utility plans to continue its cost-savings efforts. If the Utility is unable to identify, implement and sustain new cost-saving initiatives, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be adversely affected.

The CPUC also has authorized the Utility to collect rates to recover the costs of various public policy programs that provide customer incentives and subsidies for energy efficiency programs and for the development and use of renewable and self-generation technologies. In addition, the CPUC has authorized ratemaking mechanisms that permit the utilities to earn incentives (or incur a reimbursement obligation) depending on the extent to which the utilities meet the CPUC's energy savings and demand reduction goals over three-year program cycles. There is considerable uncertainty about how the costs and the savings attributable to these energy efficiency programs will be measured and verified. As customer rates rise to reflect these subsidies, customer incentives, or shareholder incentives, the risk may increase that the CPUC or another state authority will disallow recovery of some of the Utility's costs based on a determination that the costs were not reasonably incurred or for some other reason, resulting in stranded investment capital.

In addition, changes in laws and regulations or changes in the political and regulatory environment may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. During the 2000-2001 energy crisis that followed the implementation of California's electric industry restructuring, the Utility could not recover in rates the high prices it had to pay for wholesale electricity, which ultimately caused the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Even though the Chapter 11 Settlement Agreement and current regulatory mechanisms contemplate that the CPUC will give the Utility the opportunity to recover its reasonable and prudent future costs of electricity and natural gas in its rates, the CPUC may not find that all of the Utility's costs are reasonable and prudent, or the CPUC may take actions or fail to take actions that would be to the Utility's detriment. In addition, the bankruptcy court having jurisdiction of the Chapter 11 Settlement Agreement or other courts may fail to implement or enforce the terms of the Chapter 11 Settlement Agreement and the Utility's plan of reorganization in a manner that would produce the economic results that PG&E Corporation and the Utility intend or anticipate.

The Utility's failure to recover any material amount of its costs through its rates in a timely manner would have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows.

The Utility faces uncertainties associated with the future level of bundled electric load for which it must procure electricity and secure generating capacity and, under certain circumstances, may not be able to recover all of its costs.

The Utility must procure electricity to meet customer demand, plus applicable reserve margins, not satisfied from the Utility's own generation facilities and existing electricity contracts. When customer demand exceeds the amount of electricity that can be economically produced from the Utility's own generation facilities plus net energy purchase contracts (including DWR contracts allocated to the Utility's customers), the Utility will be in a "short" position. When the Utility's supply of electricity from its own generation resources plus net energy purchase contracts exceeds customer demand, the Utility is in a "long" position.

The amount of electricity the Utility needs to meet the demands of customers that is not satisfied from the Utility's own generation facilities, existing purchase contracts or DWR contracts allocated to the Utility's customers, could increase or decrease due to a variety of factors, including, without limitation, a change in the number of the Utility's customers, periodic expirations or terminations of existing electricity purchase contracts, including DWR contracts, execution of new energy and capacity purchase contracts, fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract by the Utility, implementation of new energy efficiency and demand response programs, the reallocation of the DWR power purchase contracts among California investor-owned electric utilities, and the acquisition, retirement, or closure of generation facilities. The amount of electricity the Utility would need to purchase would immediately increase if there was an unexpected outage at Diablo Canyon or any of its other significant generation facilities, if the Utility had to shut down Diablo Canyon for any reason, or if any of the counterparties to the Utility's electricity purchase contracts or the DWR allocated contracts did not perform due to bankruptcy or for some other reason. In addition, as the electricity supplier of last resort, the amount of electricity the Utility would need to purchase also would immediately increase if a material number of customers who purchase electricity from alternate energy providers (referred to as "direct access" customers) or customers of community choice aggregators (see below) decided to return to receiving bundled services from the Utility.

If the Utility's short position unexpectedly increases, the Utility would need to purchase electricity in the wholesale market under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. The inability of the Utility to purchase electricity in the wholesale market at prices or on terms the CPUC finds reasonable or in quantities sufficient to satisfy the Utility's short position could have a material adverse effect on the financial condition, results of operations or cash flow of the Utility and PG&E Corporation.

Alternatively, the Utility would be in a long position if the number of Utility customers declined because of a general economic downturn in the Utility service territory, the restoration of customer direct access after the DWR's liability for its electricity purchase contracts has ended, municipalization, or the formation and operation of community choice aggregators. California law permits California cities and counties to purchase and sell electricity for all their residents who do not affirmatively elect to continue to receive electricity from the Utility, once the city or county has registered as a community choice aggregator while the Utility continues to provide distribution, metering and billing services to the community choice aggregators' customers and serves as the electricity provider of last resort for all customers.

In addition, the Utility could lose customers, or experience lesser demand, because of increased self-generation. The risk of loss of customers and decreased demand through self-generation is increasing as the CPUC has approved various programs to provide self-generation incentives and subsidies to customers to encourage development and use of renewable and distributed generating technologies, such as solar technology. The number of the Utility's customers also could decline due to stricter greenhouse gas regulations or other state regulations that cause customers to leave the Utility's service territory.

If the Utility were in a long position the Utility would be required to sell the excess electricity purchased from third parties under electricity purchase contracts, possibly at a loss. In addition, excess electricity generated by the Utility's own generation facilities may also have to be sold, possibly at a loss, and costs the Utility may have incurred to develop or acquire new generation resources may become stranded.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility faces significant uncertainty in connection with the implementation of the CAISO's Market Redesign and Technology Upgrade program to restructure California's wholesale electricity market and the potential restructuring of the CPUC's resource adequacy program.

In response to the electricity market manipulation that occurred during the 2000-2001 energy crisis and the underlying need for improved congestion management, the CAISO has undertaken an initiative called Market Redesign and Technology Upgrade, referred to as MRTU, to implement a new day-ahead wholesale electricity market and to improve electricity grid management reliability, operational efficiencies and related technology infrastructure. MRTU will add significant market complexity and will require major changes to the Utility's systems and software interfacing with the CAISO. MRTU is scheduled to become effective in 2009. Although the CPUC has authorized the Utility to record its related incremental capital costs and expenses, the Utility's ability to recover these recorded amounts from customers will be subject to a future CPUC proceeding where the reasonableness of amounts recorded will be reviewed.

Among other features, the MRTU initiative provides that electric transmission congestion costs and credits will be determined between any two locations and charged to the market participants, including load-serving entities ("LSEs") like the Utility, that take energy that passes between those locations. The CAISO also will provide CRRs to allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. The CAISO will release CRRs through an annual and monthly process, each of which includes both an allocation phase (in which LSEs receive CRRs at no cost) and an auction phase (priced at market, and available to all market participants). The Utility has been allocated and has acquired via auction certain CRRs as of December 31, 2008, and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date to be used when MRTU commences.

If the Utility incurs significant costs to implement MRTU, including the costs associated with CRRs, that are not timely recovered from customers; if the new market mechanisms created by MRTU result in any price/market flaws that are not promptly and effectively corrected by the market mechanisms, the CAISO, or the FERC; if the Utility's CRRs are not sufficient to hedge the financial risk associated with its CAISO-imposed congestion costs under MRTU; if either the CAISO's or the Utility's MRTU-related systems and software do not perform as intended or if the CPUC adopts comprehensive changes to its resource adequacy program that materially affect the Utility's obligations under that program, the current cost of capacity, or the means by which the Utility procures that capacity, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

The Utility may fail to realize the benefits of its advanced metering system, the advanced metering system may fail to perform as intended, or the Utility may incur unrecoverable costs to deploy the advanced metering system and associated dynamic pricing, resulting in higher costs and/or reduced cost savings.

During 2006, the Utility began to implement the SmartMeter™ advanced metering infrastructure project for residential and small commercial customers. This project, which is expected to be completed by the end of 2011, involves the installation of approximately 10 million advanced electricity and gas meters throughout the Utility's service territory. Advanced meters will allow customer usage data to be transmitted through a communication network to a central collection point, where the data will be stored and used for billing and other commercial purposes.

The CPUC authorized the Utility to recover \$1.74 billion in estimated project costs, including an estimated capital cost of \$1.4 billion and approximately \$54.8 million for costs related to marketing a new demand response rate based on critical peak pricing. If additional costs exceed \$100 million, the additional costs will be subject to the CPUC's reasonableness review. On December 12, 2007, and supplemented on May 14, 2008, the Utility filed an application with the CPUC requesting approval to upgrade elements of the SmartMeter™ program at an estimated cost of approximately \$572 million, including approximately \$463 million of capital expenditures to be recovered through electric rates beginning in 2009.

The CPUC also has ordered the Utility to implement "dynamic pricing" for its electricity customers to encourage efficient energy consumption and cost-effective demand response by more closely aligning retail rates with the wholesale market. The Utility is required to have advanced metering and billing systems in place for larger customers by May 2010 to support default rates that are based on critical peak prices and time of use. The Utility is also required to start implementing default rates based on critical peak prices and time of use for small and medium non-residential customers by February 2011. The Utility estimates it will incur approximately \$155 million (including estimated capital costs of approximately \$107 million) in incremental costs by the end of 2010 to implement dynamic pricing to meet the CPUC's required schedule.

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, if the Utility incurs additional advanced metering costs that the CPUC does not find reasonable or are unrecoverable, if the Utility incurs costs to implement dynamic pricing that are not recoverable, or if the Utility cannot integrate the new advanced metering system with its billing and other computer information systems, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

If the Utility cannot timely meet the applicable resource adequacy or renewable energy requirements, the Utility may be subject to penalties.

The Utility must achieve electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements. The CPUC can impose a penalty if the Utility fails to acquire sufficient capacity to meet these resource adequacy requirements for a particular year. The penalty for failure to procure sufficient system resource adequacy capacity (i.e., resources that are deliverable anywhere in the CAISO-controlled electricity grid) is equal to three times the cost of the new capacity the Utility should have secured. The CPUC has set this penalty at \$120 per kW-year. The CPUC also adopted "local" resource adequacy requirements for specific regions in which locally-situated electricity capacity may be needed due to transmission constraints. The CPUC set the penalty for failure to meet local resource adequacy requirements at \$40 per kW-year. In addition to penalties, the CAISO can require LSEs that fail to meet their resource adequacy requirements to pay the CAISO's cost of buying electricity capacity to fulfill the LSEs' resource adequacy target levels.

In addition, the RPS established under state law requires the Utility to increase its purchases of renewable energy each year, so that the amount of electricity delivered from eligible renewable resources equals at least 20% of its total retail sales by the end of 2010. The California Legislature is considering proposals to increase the RPS mandate to at least 33% by 2020. The CPUC has established penalties of \$50 per MWh, up to \$25 million per year, for an unexcused failure to comply with the current RPS requirements. The CPUC can excuse noncompliance if a retail seller is able to demonstrate good cause, such as insufficient transmission capacity or the failure of the renewable energy provider to timely develop a renewable resource. Following several RFOs and bilateral negotiations, the Utility entered into various agreements to purchase renewable generation to be produced by facilities proposed to be developed by third parties. The development of these renewable generation facilities are subject to many risks, including risks related to permitting, financing, technology, fuel supply, environmental, and the construction of sufficient transmission capacity. The Utility has been supporting the development of these renewable resources by working with regulatory and governmental agencies to ensure timely construction of transmission lines and permitting of proposed project sites.

If the Utility fails to meet resource adequacy requirements, the Utility may be subject to penalties imposed by the CPUC and the CAISO. In addition, if the Utility fails to meet the RPS requirements, the Utility may be subject to penalties imposed by the CPUC for an unexcused failure to comply with the RPS requirements.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers as a result of municipalization, technological change, or other forms of bypass.

The Utility's customers could bypass its distribution and transportation system by obtaining service from other sources. This may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. Forms of bypass of the Utility's electricity distribution system include construction of duplicate distribution facilities to serve specific existing or new customers and condemnation of the Utility's distribution facilities by local governments or municipal districts. Also, the Utility's natural gas transportation facilities could risk being bypassed by interstate pipeline companies that construct facilities in the Utility's markets or by customers who build pipeline connections that bypass the Utility's natural gas transportation and distribution system, or by customers who use and transport LNG.

As customers and local public officials continue to explore their energy options, these bypass risks may be increasing and may increase further if the Utility's rates exceed the cost of other available alternatives.

If the number of the Utility's customers declines due to municipalization, or other forms of bypass, and the Utility's rates are not adjusted in a timely manner to allow it to fully recover its investment in electricity and natural gas facilities and electricity procurement costs, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially adversely affected.

Electricity and natural gas markets are highly volatile and regulatory responsiveness to that volatility could be insufficient. Changing commodity prices may increase short-term cash requirements.

Commodity markets for electricity and natural gas are highly volatile and subject to substantial price fluctuations. A variety of factors that are largely outside of the Utility's control may contribute to commodity price volatility, including:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- the level of production of natural gas;
- the availability of nuclear fuel;
- the availability of LNG supplies;
- the price of fuels that are used to produce electricity, including natural gas, crude oil, coal and nuclear materials;
- the transparency, efficiency, integrity and liquidity of regional energy markets affecting California;
- electricity transmission or natural gas transportation capacity constraints;
- federal, state, and local energy and environmental regulation and legislation; and
- natural disasters, war, terrorism, and other catastrophic events.

The Utility's exposure to natural gas price volatility will increase as the DWR electricity purchase contracts allocated to the Utility begin to expire or as the DWR contracts are terminated or assigned to the Utility. The final DWR contract is scheduled to expire in 2015. Although the Utility attempts to execute CPUC-approved hedging programs to reduce the natural gas price risk, these hedging programs may not be successful or the costs of the Utility's hedging programs may not be fully recoverable.

Further, if wholesale electricity or natural gas prices significantly increase, public pressure, other regulatory influences, governmental influences, or other factors could constrain the CPUC from authorizing timely recovery of the Utility's costs from customers. If the Utility cannot recover a material amount of its costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be materially adversely affected.

Economic downturn and the resulting drop in demand for energy commodities has reduced the prices of electricity and natural gas and required the Utility to deposit or return collateral in connection with its commodity hedging contracts. To the extent such commodity prices remain volatile, the Utility's liquidity and financing needs may fluctuate due to the collateral requirements associated with its commodity hedging contracts. If the Utility is required to finance higher liquidity levels, the increased interest costs may negatively impact net income.

The Utility's financial condition and results of operations could be materially adversely affected if it cannot successfully manage the risks inherent in operating the Utility's facilities.

The Utility owns and operates extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The operation of the Utility's facilities and the facilities of third parties on which it relies involves numerous risks, the realization of which can affect demand for electricity or natural gas, result in unplanned outages, reduce generating output, cause damage to the Utility's assets or operations or those of third parties on which it relies, or subject the Utility to third party claims or liability for damage or injury. These risks include:

- operating limitations that may be imposed by environmental laws or regulations, including those relating to greenhouse gases, or other regulatory requirements;
- imposition of stricter operational performance standards by agencies with regulatory oversight of the Utility's facilities;
- environmental accidents, including the release of hazardous or toxic substances into the air or water, urban wildfires and other events caused by operation of the Utility's facilities or equipment failure;
- fuel supply interruptions;
- equipment failure;
- failure of the Utility's computer information systems, including those relating to operations or financial information such as customer billing;
- labor disputes, workforce shortage, and availability of qualified personnel;
- weather, storms, earthquakes, wild land and other fires, floods or other natural disasters, war, pandemic and other catastrophic events;
- explosions, accidents, dam failure, mechanical breakdowns, and terrorist activities; and
- other events or hazards.

The Utility has undertaken a thorough review of its operating practices and procedures used in its natural gas system, including its gas leak survey practices. The Utility has determined that improvements need to be made to operating practices and procedures, including increasing the accuracy of gas maintenance records and compliance with operating procedures. In addition, the Utility intends to accelerate the work associated with system-wide gas leak surveys and targets completing this work in a little more than a year. The Utility forecasts that it will spend up to \$100 million more in 2009 to perform the gas leak surveys and associated remedial work on the accelerated schedule. The CPUC's Consumer Protection and Safety Division is conducting an informal investigation of the Utility's natural gas distribution maintenance practices and the Utility has provided information about the Utility's review and the remedial steps the Utility has taken. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially adversely affected if the Utility were to incur material costs or other material liabilities in connection with these operational issues that were not recoverable through rates or otherwise offset by operating efficiencies or other revenues.

In addition, the Utility's insurance may not be sufficient or effective to provide recovery under all circumstances or against all hazards or liabilities to which the Utility is or may become subject. An uninsured loss could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows. Future insurance coverage may not be available at rates and on terms as favorable as the rates and terms of the Utility's current insurance coverage.

The Utility may experience a labor shortage if it is unable to attract and retain qualified personnel to replace employees who retire or leave for other reasons or the Utility's operations may be affected by labor disruptions as a substantial number of employees are covered by collective bargaining agreements that are subject to re-negotiation as their terms expire.

The Utility's workforce is aging and many employees will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may not be successful. The Utility may be faced with a shortage of experienced and qualified personnel that could negatively impact the Utility's operations as well as its financial condition and results of operations.

At December 31, 2008, there were 14,649 Utility employees covered by collective bargaining agreements with three unions. The terms of these agreements impact the Utility's labor costs. While these contracts are re-negotiated, it is possible that labor disruptions could occur. In addition, it is possible that some of the remaining non-represented Utility employees will join one of these unions in the future.

The Utility's future operations may be impacted by climate change that may have a material impact on the Utility's financial condition and results of operations.

There is substantial uncertainty about the potential impacts of climate change on the Utility's electricity and natural gas operations and whether climate change is responsible for increased frequency and severity of hot weather, including potentially decreased hydroelectric generation resulting from reduced runoff from snow pack and increased sea level along the Northern California coastal area. If climate change reduces the Utility's hydroelectric generation capacity, there will be a need for additional generation capacity even if there is no change in average load. The impact of events caused by climate change could range widely, with highly localized to worldwide effects, and under certain conditions could result in a full or partial disruption of the ability of the Utility or one or more entities on which it relies to generate, transmit, transport or distribute electricity or natural gas. Even the less extreme events could result in lower revenues or increased expenses, or both; increased expenses may not be fully recovered through rates or other means in a timely manner or at all, and decreased revenues may negatively impact otherwise anticipated rates of return.

The Utility's operations are subject to extensive environmental laws, and changes in, or liabilities under these laws could adversely affect its financial condition and results of operations.

The Utility's operations are subject to extensive federal, state, and local environmental laws and permits. Complying with these environmental laws has, in the past, required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Compliance in the future may require significant expenditures relating to reduction of greenhouse gases, regulation of water intake or discharge at certain facilities, and mitigation measures associated with electric and magnetic fields. Generally, the Utility has recovered the costs of complying with environmental laws and regulation in the Utility's rates, subject to reasonableness review.

New California legislation imposes a state-wide limit on the emission of greenhouse gases that must be achieved by 2020 and prohibits LSEs, including investor-owned utilities, from entering into long-term financial commitments for generation resources unless the new generation resources conform to a greenhouse gas emission performance standard. The California Air Resources Board has proposed to implement a regional cap-and-trade program for greenhouse gas emissions focusing on the electricity and large industrial facility sectors beginning in 2012, and expanding to transportation and natural gas in 2015. Depending on how the baseline for greenhouse gas emissions level is set and how the cap-and-trade market system develops, the Utility could incur significant additional costs to ensure that it complies with the new rules as a generation owner. In addition, the price to procure electricity from other generation providers will be affected by the costs of compliance with the new rules. Although these costs are expected to be passed through to customers, there can be no assurance that the CPUC will permit full recovery of these costs especially if costs increase due to market manipulation.

In addition, the Utility already has significant liabilities (currently known, unknown, actual, and potential) related to environmental contamination at current and former Utility facilities, including natural gas compressor stations and former manufactured gas plants, as well as at third-party owned sites. The CPUC has established a special ratemaking mechanism under which the Utility is authorized to recover 90% of environmental costs associated with the clean-up of sites that contain hazardous substances (subject to some exceptions) without a reasonableness review. There is no guarantee that the CPUC will not discontinue or change this ratemaking mechanism in the future.

The Utility's environmental compliance and remediation costs could increase, and the timing of its future capital expenditures may accelerate, if standards become stricter, regulation increases, other potentially responsible parties cannot or do not contribute to cleanup costs, conditions change or additional contamination is discovered. If the Utility must pay materially more than the amount that it currently has accrued on its Consolidated Balance Sheets to satisfy its environmental remediation obligations and cannot recover those or other costs of complying with environmental laws in its rates in a timely manner, or at all, PG&E Corporation's and the Utility's financial condition, results of operations and cash flow would be materially adversely affected.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures that it may not be able to recover from its insurance or other source, adversely affecting its financial condition, results of operations and cash flow.

Operating and decommissioning the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures, including not only the risk of death, injury and property damage from a nuclear accident, but matters arising from the storage, handling and disposal of radioactive materials, including spent nuclear fuel; stringent safety and security requirements; public and political opposition to nuclear power operations; and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants when their licenses expire. The Utility maintains insurance and decommissioning trusts to reduce the Utility's financial exposure to these risks. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of the Utility's insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, the Utility may be required under federal law to pay up to \$235 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility, but at any other nuclear power plant in the United States.

The NRC has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. If they do not comply, the NRC can impose fines or force a shutdown of the nuclear plant, or both, depending upon the NRC's assessment of the severity of the situation. 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. In addition, as required by NRC regulations, only certain key management personnel and other designated individuals may receive information from the NRC or other government agency relating to Diablo Canyon that is deemed to be classified by the governmental agency. In connection with this requirement, the Board of Directors of PG&E Corporation has adopted a resolution acknowledging that neither PG&E Corporation nor any director or officer of PG&E Corporation will (1) have access to such classified information or special nuclear material in the custody of the Utility, or (2) participate in any decision or matter pertaining to the protection of classified information and/or special nuclear material in the custody of the Utility. If one or both units at Diablo Canyon were shut down pursuant to an NRC order, or to comply with NRC licensing, safety or security requirements, or due to other safety or operational issues, the Utility's operating and maintenance costs would increase. Further, such events may cause the Utility to be in a short position and the Utility would need to purchase electricity from more expensive sources. In addition, the Utility's nuclear power operations are subject to the availability of adequate nuclear fuel supplies on terms that the CPUC will find reasonable.

The NRC operating licenses for Diablo Canyon require sufficient storage capacity for the radioactive spent fuel it produces. Because the U.S. Department of Energy has failed to develop a permanent national repository for the nation's spent nuclear fuel and high-level radioactive waste produced by the nation's nuclear electric generation facilities, the Utility has been storing spent nuclear fuel and high-level radioactive waste resulting from its nuclear operations at Diablo Canyon in on-site storage pools. The Utility also obtained a permit to construct an on-site dry cask storage facility to store spent fuel through at least 2024. An appeal related to the NRC's permit is pending. (See the discussion above under "Regulatory Matters" and Note 13 of the Notes to the Consolidated Financial Statements.) The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage will begin in June 2009. If the Utility is unable to begin loading spent fuel by October 2010 for Unit 1 or May 2011 for Unit 2 and the Utility is otherwise unable to increase its on-site storage capacity, the Utility would have to curtail or halt operations of the unit until such time as additional safe storage for spent fuel is made available.

Furthermore, certain aspects of the Utility's nuclear operations are subject to other federal, state, and local regulatory requirements that are overseen by other federal, state, or local agencies. For example, as discussed above under "Environmental Matters," there is substantial uncertainty concerning the final form of federal and state regulations to implement Section 316(b) of the Clean Water Act. Depending on the nature of the final regulations that may ultimately be adopted by the EPA, the Water Board, or the California Legislature, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the federal or state final regulations require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon.

If the CPUC prohibits the Utility from recovering a material amount of its capital expenditures, nuclear fuel costs, operating and maintenance costs, or additional procurement costs due to a determination that the costs were not reasonably or prudently incurred, PG&E Corporation's and the Utility's financial condition, results of operations and cash flow would be materially adversely affected.

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

The Utility must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of the CPUC, the FERC, the NRC, and other regulatory agencies relating to the aspects of its electricity and natural gas utility operations that fall within the jurisdictional authority of such agencies. These include customer billing, customer service, affiliate transactions, vegetation management, and safety and inspection practices. The Utility is subject to fines and penalties for failure to comply with applicable statutes, regulations, rules, tariffs and orders.

For example, under the Energy Policy Act of 2005, the FERC can impose penalties (up to \$1 million per day per violation) for failure to comply with mandatory electric reliability standards. In the fourth quarter of 2009, the Utility will undergo its first regularly-scheduled triennial audit for compliance with these standards.

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

The Utility also must comply with the terms of various permits, authorizations, and licenses. These permits, authorizations, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses often have a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

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

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

	Year ended December 31,		
	2008	2007	2006
Operating Revenues			
Electric	\$ 10,738	\$ 9,480	\$ 8,752
Natural gas	3,890	3,757	3,787
Total operating revenues	14,628	13,237	12,539
Operating Expenses			
Cost of electricity	4,425	3,437	2,922
Cost of natural gas	2,090	2,035	2,097
Operating and maintenance	4,201	3,881	3,703
Depreciation, amortization, and decommissioning	1,651	1,770	1,709
Total operating expenses	12,367	11,123	10,431
Operating Income	2,261	2,114	2,108
Interest income	94	164	188
Interest expense	(728)	(762)	(738)
Other income (expense), net	(18)	29	(13)
Income Before Income Taxes	1,609	1,545	1,545
Income tax provision	425	539	554
Income From Continuing Operations	1,184	1,006	991
Discontinued Operations			
NEGT income tax benefit	154	-	-
Net Income	\$ 1,338	\$ 1,006	\$ 991
Weighted Average Common Shares Outstanding, Basic	357	351	346
Weighted Average Common Shares Outstanding, Diluted	358	353	349
Earnings Per Common Share from Continuing Operations, Basic	\$ 3.23	\$ 2.79	\$ 2.78
Net Earnings Per Common Share, Basic	\$ 3.64	\$ 2.79	\$ 2.78
Earnings Per Common Share from Continuing Operations, Diluted	\$ 3.22	\$ 2.78	\$ 2.76
Net Earnings Per Common Share, Diluted	\$ 3.63	\$ 2.78	\$ 2.76
Dividends Declared Per Common Share	\$ 1.56	\$ 1.44	\$ 1.32

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2008	2007
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 219	\$ 345
Restricted cash	1,290	1,297
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$76 million in 2008 and \$58 million in 2007)	1,751	1,599
Accrued unbilled revenue	685	750
Regulatory balancing accounts	1,197	771
Inventories:		
Gas stored underground and fuel oil	232	205
Materials and supplies	191	166
Income taxes receivable	120	61
Prepaid expenses and other	718	255
Total current assets	6,403	5,449
Property, Plant, and Equipment		
Electric	27,638	25,599
Gas	10,155	9,620
Construction work in progress	2,023	1,348
Other	17	17
Total property, plant, and equipment	39,833	36,584
Accumulated depreciation	(13,572)	(12,928)
Net property, plant, and equipment	26,261	23,656
Other Noncurrent Assets		
Regulatory assets	5,996	4,459
Nuclear decommissioning funds	1,718	1,979
Other	482	1,089
Total other noncurrent assets	8,196	7,527
TOTAL ASSETS	\$ 40,860	\$ 36,632

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2008	2007
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 287	\$ 519
Long-term debt, classified as current	600	-
Energy recovery bonds, classified as current	370	354
Accounts payable:		
Trade creditors	1,096	1,067
Disputed claims and customer refunds	1,580	1,629
Regulatory balancing accounts	730	673
Other	343	394
Interest payable	802	697
Deferred income taxes	251	-
Other	1,567	1,374
Total current liabilities	7,626	6,707
Noncurrent Liabilities		
Long-term debt	9,321	8,171
Energy recovery bonds	1,213	1,582
Regulatory liabilities	3,657	4,448
Pension and other postretirement benefits	2,088	-
Asset retirement obligations	1,684	1,579
Income taxes payable	35	234
Deferred income taxes	3,397	3,053
Deferred tax credits	94	99
Other	2,116	1,954
Total noncurrent liabilities	23,605	21,120
Commitments and Contingencies		
Preferred Stock of Subsidiaries	252	252
Preferred Stock		
Preferred stock, no par value, authorized 80,000,000 shares, \$100 par value, authorized 5,000,000 shares, none issued	-	-
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 361,059,116 common and 1,287,569 restricted shares in 2008 and issued 378,385,151 common and 1,261,125 restricted shares in 2007	5,984	6,110
Common stock held by subsidiary, at cost, 24,665,500 shares in 2007	-	(718)
Reinvested earnings	3,614	3,151
Accumulated other comprehensive income (loss)	(221)	10
Total common shareholders' equity	9,377	8,553
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 40,860	\$ 36,632

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2008	2007	2006
Cash Flows From Operating Activities			
Net income	\$ 1,338	\$ 1,006	\$ 991
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,863	1,959	1,803
Allowance for equity funds used during construction	(70)	(64)	(47)
Gain on sale of assets	(1)	(1)	(11)
Deferred income taxes and tax credits, net	590	55	(285)
Other changes in noncurrent assets and liabilities	(126)	192	151
Effect of changes in operating assets and liabilities:			
Accounts receivable	(87)	(6)	130
Inventories	(59)	(41)	32
Accounts payable	(140)	(178)	17
Income taxes receivable/payable	(59)	56	124
Regulatory balancing accounts, net	(394)	(567)	329
Other current assets	(221)	172	(273)
Other current liabilities	120	8	(233)
Other	(5)	(45)	(14)
Net cash provided by operating activities	2,749	2,546	2,714
Cash Flows From Investing Activities			
Capital expenditures	(3,628)	(2,769)	(2,402)
Net proceeds from sale of assets	26	21	17
Decrease in restricted cash	36	185	115
Proceeds from nuclear decommissioning trust sales	1,635	830	1,087
Purchases of nuclear decommissioning trust investments	(1,684)	(933)	(1,244)
Other	(37)	-	-
Net cash used in investing activities	(3,652)	(2,666)	(2,427)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and revolving credit facility	533	850	350
Repayments under accounts receivable facility and revolving credit facility	(783)	(900)	(310)
Net issuance (repayments) of commercial paper, net of discount of \$11 million in 2008, \$1 million in 2007 and \$2 million in 2006	6	(209)	458
Proceeds from issuance of long-term debt, net of discount, premium and issuance costs of \$19 million in 2008 and \$16 million in 2007	2,185	1,184	-
Long-term debt repurchased	(454)	-	-
Rate reduction bonds matured	-	(290)	(290)
Energy recovery bonds matured	(354)	(340)	(316)
Common stock issued	225	175	131
Common stock repurchased	-	-	(114)
Common stock dividends paid	(546)	(496)	(456)
Other	(35)	35	3
Net cash provided by (used in) financing activities	777	9	(544)
Net change in cash and cash equivalents	(126)	(111)	(257)
Cash and cash equivalents at January 1	345	456	713
Cash and cash equivalents at December 31	\$ 219	\$ 345	\$ 456
Supplemental disclosures of cash flow information			
Cash paid (received) for:			
Interest (net of amounts capitalized)	\$ 523	\$ 514	\$ 503
Income taxes, net	(112)	537	736
Supplemental disclosures of noncash investing and financing activities			
Common stock dividends declared but not yet paid	\$ 143	\$ 129	\$ 117
Capital expenditures financed through accounts payable	348	279	215
Stock issued in lieu of dividend	20	5	-
Assumption of capital lease obligation	-	-	408
Transfer of Gateway Generating Station asset	-	-	69

See accompanying Notes to the Consolidated Financial Statements.

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

	Common Stock Shares	Common Stock Amount	Common Stock Held by Subsidiary	Unearned Compensation	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Share- holders' Equity	Comprehensive Income
Balance at December 31, 2005	368,268,502	\$ 5,827	\$ (718)	\$ (22)	\$ 2,139	\$ (8)	\$ 7,218	
Net income	-	-	-	-	991	-	991	\$ 991
Comprehensive income								<u>\$ 991</u>
Common stock issued	5,399,707	110	-	-	-	-	110	
Accelerated share repurchase settlement of stock repurchased in 2005	-	(114)	-	-	-	-	(114)	
Common stock warrants exercised	51,890	-	-	-	-	-	-	
Common restricted stock, unearned compensation reversed in accordance with SFAS No. 123R	-	(22)	-	22	-	-	-	
Common restricted stock issued	566,255	21	-	-	-	-	21	
Common restricted stock cancelled	(105,295)	(1)	-	-	-	-	(1)	
Common restricted stock amortization	-	20	-	-	-	-	20	
Common stock dividends declared and paid	-	-	-	-	(342)	-	(342)	
Common stock dividends declared but not yet paid	-	-	-	-	(117)	-	(117)	
Tax benefit from employee stock plans	-	35	-	-	-	-	35	
Adoption of SFAS No. 158 (net of income tax benefit of \$8 million)	-	-	-	-	-	(11)	(11)	
Other	-	1	-	-	-	-	1	
Balance at December 31, 2006	374,181,059	5,877	(718)	-	2,671	(19)	7,811	
Net income	-	-	-	-	1,006	-	1,006	\$ 1,006
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax expense of \$17 million)	-	-	-	-	-	29	29	29
Comprehensive income								<u>\$ 1,035</u>
Common stock issued, net	5,465,217	175	-	-	-	-	175	
Stock-based compensation amortization	-	31	-	-	-	-	31	
Common stock dividends declared and paid	-	-	-	-	(379)	-	(379)	
Common stock dividends declared but not yet paid	-	-	-	-	(129)	-	(129)	
Tax benefit from employee stock plans	-	27	-	-	-	-	27	
Adoption of FIN 48	-	-	-	-	(18)	-	(18)	
Balance at December 31, 2007	379,646,276	6,110	(718)	-	3,151	10	8,553	

Net income	-	-	-	-	1,338	-	1,338	\$ 1,338
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax benefit of \$156 million)						(231)	(231)	(231)
Comprehensive income								<u>\$ 1,107</u>
Common stock issued, net	7,365,909	247	-	-	-	-	247	
Common stock cancelled	(24,665,500)	(403)	718	-	(315)	-	-	
Stock-based compensation amortization	-	24	-	-	-	-	24	
Common stock dividends declared and paid	-	-	-	-	(417)	-	(417)	
Common stock dividends declared but not yet paid	-	-	-	-	(143)	-	(143)	
Tax benefit from employee stock plans	-	6	-	-	-	-	6	
Balance at December 31, 2008	<u><u>362,346,685</u></u>	<u><u>\$ 5,984</u></u>	<u><u>\$ -</u></u>	<u><u>\$ -</u></u>	<u><u>\$ 3,614</u></u>	<u><u>\$ (221)</u></u>	<u><u>\$ 9,377</u></u>	

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2008	2007	2006
Operating Revenues			
Electric	\$ 10,738	\$ 9,481	\$ 8,752
Natural gas	3,890	3,757	3,787
Total operating revenues	14,628	13,238	12,539
Operating Expenses			
Cost of electricity	4,425	3,437	2,922
Cost of natural gas	2,090	2,035	2,097
Operating and maintenance	4,197	3,872	3,697
Depreciation, amortization and decommissioning	1,650	1,769	1,708
Total operating expenses	12,362	11,113	10,424
Operating Income	2,266	2,125	2,115
Interest income	91	150	175
Interest expense	(698)	(732)	(710)
Other income, net	28	52	7
Income Before Income Taxes	1,687	1,595	1,587
Income tax provision	488	571	602
Net Income	1,199	1,024	985
Preferred stock dividend requirement	14	14	14
Income Available for Common Stock	\$ 1,185	\$ 1,010	\$ 971

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance At December 31,	
	2008	2007
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 52	\$ 141
Restricted cash	1,290	1,297
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$76 million in 2008 and \$58 million in 2007)	1,751	1,599
Accrued unbilled revenue	685	750
Related parties	2	6
Regulatory balancing accounts	1,197	771
Inventories:		
Gas stored underground and fuel oil	232	205
Materials and supplies	191	166
Income taxes receivable	25	15
Prepaid expenses and other	705	252
Total current assets	6,130	5,202
Property, Plant, and Equipment		
Electric	27,638	25,599
Gas	10,155	9,620
Construction work in progress	2,023	1,348
Total property, plant, and equipment	39,816	36,567
Accumulated depreciation	(13,557)	(12,913)
Net property, plant, and equipment	26,259	23,654
Other Noncurrent Assets		
Regulatory assets	5,996	4,459
Nuclear decommissioning funds	1,718	1,979
Related parties receivable	27	23
Other	407	993
Total other noncurrent assets	8,148	7,454
TOTAL ASSETS	\$ 40,537	\$ 36,310

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2008	2007
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 287	\$ 519
Long-term debt, classified as current	600	-
Energy recovery bonds, classified as current	370	354
Accounts payable:		
Trade creditors	1,096	1,067
Disputed claims and customer refunds	1,580	1,629
Related parties	25	28
Regulatory balancing accounts	730	673
Other	325	370
Interest payable	802	697
Income tax payable	53	-
Deferred income taxes	257	4
Other	1,371	1,200
Total current liabilities	7,496	6,541
Noncurrent Liabilities		
Long-term debt	9,041	7,891
Energy recovery bonds	1,213	1,582
Regulatory liabilities	3,657	4,448
Pension and other postretirement benefits	2,040	-
Asset retirement obligations	1,684	1,579
Income taxes payable	12	103
Deferred income taxes	3,449	3,104
Deferred tax credits	94	99
Other	2,064	1,838
Total noncurrent liabilities	23,254	20,644
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	113	113
Common stock, \$5 par value, authorized 800,000,000 shares, issued 264,374,809 shares in 2008 and issued 282,916,485 shares in 2007	1,322	1,415
Common stock held by subsidiary, at cost, 19,481,213 shares in 2007	-	(475)
Additional paid-in capital	2,331	2,220
Reinvested earnings	6,092	5,694
Accumulated other comprehensive income (loss)	(216)	13
Total shareholders' equity	9,787	9,125
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 40,537	\$ 36,310

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2008	2007	2006
Cash Flows From Operating Activities			
Net income	\$ 1,199	\$ 1,024	\$ 985
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,838	1,956	1,802
Allowance for equity funds used during construction	(70)	(64)	(47)
Gain on sale of assets	(1)	(1)	(11)
Deferred income taxes and tax credits, net	593	43	(287)
Other changes in noncurrent assets and liabilities	(25)	188	116
Effect of changes in operating assets and liabilities:			
Accounts receivable	(83)	(6)	128
Inventories	(59)	(41)	34
Accounts payable	(137)	(196)	21
Income taxes receivable/payable	43	56	28
Regulatory balancing accounts, net	(394)	(567)	329
Other current assets	(223)	170	(273)
Other current liabilities	90	24	(235)
Other	(5)	(45)	(13)
Net cash provided by operating activities	2,766	2,541	2,577
Cash Flows From Investing Activities			
Capital expenditures	(3,628)	(2,768)	(2,402)
Net proceeds from sale of assets	26	21	17
Decrease in restricted cash	36	185	115
Proceeds from nuclear decommissioning trust sales	1,635	830	1,087
Purchases of nuclear decommissioning trust investments	(1,684)	(933)	(1,244)
Other	(25)	-	1
Net cash used in investing activities	(3,640)	(2,665)	(2,426)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and revolving credit facility	533	850	350
Repayments under accounts receivable facility and revolving credit facility	(783)	(900)	(310)
Net issuance (repayments) of commercial paper, net of discount of \$11 million in 2008, \$1 million in 2007 and \$2 million in 2006	6	(209)	458
Proceeds from issuance of long-term debt, net of discount, premium and issuance costs of \$19 million in 2008 and \$16 million in 2007	2,185	1,184	-
Long-term debt repurchased	(454)	-	-
Rate reduction bonds matured	-	(290)	(290)
Energy recovery bonds matured	(354)	(340)	(316)
Preferred stock dividends paid	(14)	(14)	(14)
Common stock dividends paid	(568)	(509)	(460)
Equity contribution	270	400	-
Other	(36)	23	38
Net cash provided by (used in) financing activities	785	195	(544)
Net change in cash and cash equivalents	(89)	71	(393)
Cash and cash equivalents at January 1	141	70	463
Cash and cash equivalents at December 31	\$ 52	\$ 141	\$ 70
Supplemental disclosures of cash flow information			
Cash paid (received) for:			
Interest (net of amounts capitalized)	\$ 496	\$ 474	\$ 476
Income taxes, net	(95)	594	897
Supplemental disclosures of noncash investing and financing activities			
Capital expenditures financed through accounts payable	\$ 348	\$ 279	\$ 215
Assumption of capital lease obligation	-	-	408
Transfer of Gateway Generating Station asset	-	-	69

See accompanying Notes to the Consolidated Financial Statements.

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

	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Accumulated Other Comprehensive Income (Loss)	Total Share- holders' Equity	Comprehensive Income
Balance at December 31, 2005	\$ 258	\$ 1,398	\$ 1,776	\$ (475)	\$ 4,702	\$ (9)	\$ 7,650	
Net income	-	-	-	-	985	-	985	\$ 985
Minimum pension liability adjustment (net of income tax expense of \$2 million)	-	-	-	-	-	3	3	3
Comprehensive income								<u>\$ 988</u>
Tax benefit from employee stock plans	-	-	46	-	-	-	46	
Common stock dividend	-	-	-	-	(460)	-	(460)	
Preferred stock dividend	-	-	-	-	(14)	-	(14)	
Adoption of SFAS No. 158 (net of income tax benefit of \$7 million)	-	-	-	-	-	(10)	(10)	
Balance at December 31, 2006	258	1,398	1,822	(475)	5,213	(16)	8,200	
Net income	-	-	-	-	1,024	-	1,024	\$ 1,024
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax expense of \$17 million)	-	-	-	-	-	29	29	29
Comprehensive income								<u>\$ 1,053</u>
Equity contribution	-	17	383	-	-	-	400	
Tax benefit from employee stock plans	-	-	15	-	-	-	15	
Common stock dividend	-	-	-	-	(509)	-	(509)	
Preferred stock dividend	-	-	-	-	(14)	-	(14)	
Adoption of FIN 48	-	-	-	-	(20)	-	(20)	
Balance at December 31, 2007	258	1,415	2,220	(475)	5,694	13	9,125	
Net income	-	-	-	-	1,199	-	1,199	\$ 1,199
Employee benefit plan adjustment in accordance with SFAS No. 158 (net of income tax expense of \$159 million)	-	-	-	-	-	(229)	(229)	(229)
Comprehensive income								<u>\$ 970</u>
Equity contribution	-	4	266	-	-	-	270	
Tax benefit from employee stock plans	-	-	4	-	-	-	4	
Common stock dividend	-	-	-	-	(568)	-	(568)	
Common stock cancelled	-	(97)	(159)	475	(219)	-	-	
Preferred stock dividend	-	-	-	-	(14)	-	(14)	
Balance at December 31, 2008	\$ 258	\$ 1,322	\$ 2,331	\$ -	\$ 6,092	\$ (216)	\$ 9,787	

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company (“Utility”), a public utility operating in northern and central California. The Utility engages in the businesses of electricity and natural gas distribution; electricity generation, procurement, and transmission; and natural gas procurement, transportation, and storage. The Utility is primarily regulated by the California Public Utilities Commission (“CPUC”) and the Federal Energy Regulatory Commission (“FERC”).

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation’s Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility’s Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries as well as the accounts of variable interest entities for which the Utility absorbs a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”) requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict. Some of the more critical estimates and assumptions, discussed further below in these notes, relate to the Utility’s regulatory assets and liabilities, environmental remediation liability, asset retirement obligations (“ARO”), income tax-related assets and liabilities, pension plan and other post-retirement plan obligations, and accruals for legal matters. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation and the Utility’s financial condition and results of operations during the period in which such change occurred.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the CPUC and the FERC.

Cash and Cash Equivalents

Invested cash and other short-term investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation and the Utility primarily invest their cash in money market funds.

Restricted Cash

Restricted cash consists primarily of the Utility’s cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility’s proceeding under Chapter 11 of the U.S. Bankruptcy Code (“Chapter 11”). (See Note 15 of the Notes to the Consolidated Financial Statements.) Restricted cash also includes the Utility deposits of cash and cash equivalents made under certain third-party agreements.

Allowance for Doubtful Accounts Receivable

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, delinquency rates, current economic conditions, and assessment of customer collectability. If circumstances require changes in the assumption, allowance estimates are adjusted accordingly.

Inventories

Inventories are carried at average cost and are valued at the lower of average cost or market. Inventories include materials, supplies, and natural gas stored underground. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when consumed or installed. Natural gas stored underground represents purchases that are injected into inventory and then expensed at average cost when withdrawn and distributed to customers or used in electric generation.

Property, Plant, and Equipment

Property, plant, and equipment are reported at their original cost. These original costs include labor and materials, construction overhead, and allowance for funds used during construction (“AFUDC”).

The Utility's balances as of December 31, 2008 are as follows:

(in millions)	Gross Plant as of December 31, 2008	Accumulated Depreciation as of December 31, 2008	Net Plant as of December 31, 2008
Electricity generating facilities	\$ 3,711	\$ (1,134)	\$ 2,577
Electricity distribution facilities	18,777	(6,722)	12,055
Electricity transmission	5,150	(1,675)	3,475
Natural gas distribution facilities	6,666	(2,544)	4,122
Natural gas transportation	3,434	(1,482)	1,952
Natural gas storage	55	-	55
CWIP	2,023	-	2,023
Total	<u>\$ 39,816</u>	<u>\$ (13,557)</u>	<u>\$ 26,259</u>

The Utility's balances as of December 31, 2007 are as follows:

(in millions)	Gross Plant as of December 31, 2007	Accumulated Depreciation as of December 31, 2007	Net Plant as of December 31, 2007
Electricity generating facilities	\$ 3,004	\$ (1,040)	\$ 1,964
Electricity distribution facilities	17,712	(6,377)	11,335
Electricity transmission	4,883	(1,633)	3,250
Natural gas distribution facilities	6,302	(2,429)	3,873
Natural gas transportation	3,271	(1,434)	1,837
Natural gas storage	47	-	47
CWIP	1,348	-	1,348
Total	<u>\$ 36,567</u>	<u>\$ (12,913)</u>	<u>\$ 23,654</u>

AFUDC

AFUDC represents a method used to compensate the Utility for the estimated cost of debt and equity used to finance regulated plant additions and is recorded as part of the cost of construction projects. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. The Utility recorded AFUDC of approximately \$70 million and \$44 million during 2008, \$64 million and \$32 million during 2007, and \$47 million and \$20 million during 2006, related to equity and debt, respectively.

Depreciation

The Utility's composite depreciation rate was 3.38% in 2008, 3.28% in 2007, and 3.09% in 2006.

	Estimated Useful Lives
Electricity generating facilities	4 to 37 years
Electricity distribution facilities	16 to 58 years
Electricity transmission	40 to 70 years
Natural gas distribution facilities	24 to 52 years
Natural gas transportation	25 to 45 years
Natural gas storage	25 to 48 years

The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC and depreciation expense is included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal and remediation costs, net of any salvage value at retirement.

The Utility charges the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71 "Accounting for the Effects of Certain Types of Regulation" as amended ("SFAS No. 71"). PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel

Property, plant, and equipment also include nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output.

Capitalized Software Costs

PG&E Corporation and the Utility account for internal software in accordance with the American Institute of Certified Public Accountants Statement of Position, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use" ("SOP 98-1").

Under SOP 98-1, PG&E Corporation and the Utility capitalize costs incurred during the application development stage of internal use software projects to property, plant, and equipment. The Utility's capitalized software costs totaled \$522 million at December 31, 2008 and \$533 million at December 31, 2007, net of accumulated amortization of approximately \$280 million at December 31, 2008 and \$207 million at December 31, 2007. PG&E Corporation's capitalized software costs were less than \$1 million at December 31, 2008. PG&E Corporation and the Utility amortize capitalized software costs ratably over the expected lives of the software ranging from 3 to 15 years, commencing upon operational use.

Regulation and SFAS No. 71

The Utility accounts for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in rates in the future. The regulatory assets are amortized over future periods consistent with the inclusion of those costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are currently being recovered through rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities.

Intangible Assets

Intangible assets primarily consist of hydroelectric facility licenses and other agreements, with lives ranging from 19 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately \$95 million at December 31, 2008 and \$97 million at December 31, 2007. The accumulated amortization was approximately \$35 million at December 31, 2008 and \$32 million at December 31, 2007. In December 2008, the Utility obtained intangible assets related to the acquisition of development rights of the Tesla Generating Station. The value of these intangible assets, including permit and licenses, was approximately \$23 million at December 31, 2008. These intangible assets have indefinite lives and will not be amortized, but an impairment test will be performed annually.

The Utility's amortization expense related to intangible assets was approximately \$4 million in 2008 and \$3 million in both 2007 and 2006. The estimated annual amortization expense for 2009 through 2013 based on the December 31, 2008 intangible asset balance is approximately \$4 million each year. Intangible assets are recorded to Other Noncurrent Assets - Other in the Consolidated Balance Sheets.

Consolidation of Variable Interest Entities

The Financial Accounting Standards Board ("FASB") Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" ("FIN 46R"), provides that an entity is a variable interest entity ("VIE") if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the holder subject to the majority of the risk of loss from a VIE's activities must consolidate the VIE. However, if no holder has the majority of the risk of loss, then a holder entitled to receive a majority of the entity's residual returns would consolidate the entity.

The majority of the Utility's involvement with VIEs is through power purchase agreements. The Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a VIE owning one or more plants that sell substantially all of their output to the Utility. The Utility performs a quantitative assessment of power purchase agreements under FIN 46R, which includes performing an analysis considering the term of the contract compared to the remaining useful life of the plant, as well as performing an analysis of the absorption of the expected risks and rewards of the project including production risk, commodity price risk, credit risk, and tax attributes.

At December 31, 2008 there was one significant VIE. In 2007, the Utility entered into a 25-year agreement to purchase as-available electric generation output from an approximately 554-megawatt (“MW”) solar trough facility in which the Utility has a significant variable interest. Activities of this facility consist of renewable energy production from a single facility for sale to third parties. The VIE is a subsidiary of a privately held company and its activities are financed primarily through equity from investors and proceeds from non-recourse project-specific debt financing. The Utility is not considered the primary beneficiary for this VIE, as it will not absorb the majority of the entity’s expected losses or residual returns. Accordingly, the Utility has not consolidated this VIE in its consolidated financial statements. This project is expected to become operational in 2011 and no payments for energy have been made to this facility as of December 31, 2008.

The Utility is generally not subject to risk of loss from power purchase agreements as the primary obligation, according to the terms of the agreements, is to purchase as-available energy that is produced by the facility. Future payments to this facility are made based on the energy produced and are expected to be recoverable through customer rates. Additionally, no financial or other support was provided by the Utility to this VIE as of December 31, 2008.

Asset Retirement Obligations

PG&E Corporation and the Utility account for ARO in accordance with SFAS No. 143, “Accounting for Asset Retirement Obligations” (“SFAS No. 143”) and FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143” (“FIN 47”). SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value, and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process. FIN 47 clarifies that if a legal obligation to perform an asset retirement obligation exists but performance is conditional upon a future event, and the obligation can be reasonably estimated, then a liability should be recognized in accordance with SFAS No. 143.

The Utility has ARO for its nuclear generation and certain fossil fuel generation facilities. The Utility has also identified ARO related to asbestos contamination in buildings, potential site restoration at certain hydroelectric facilities, fuel storage tanks, and contractual obligations to restore leased property to pre-lease condition. Additionally, the Utility has recorded ARO related to the California Gas Transmission pipeline, gas distribution, electric distribution, and electric transmission system assets.

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

(in millions)	
ARO liability at December 31, 2006	\$ 1,466
Revision in estimated cash flows	48
Accretion	95
Liabilities settled	(30)
ARO liability at December 31, 2007	1,579
Revision in estimated cash flows	50
Accretion	106
Liabilities settled	(51)
ARO liability at December 31, 2008	<u>\$ 1,684</u>

The Utility has identified additional ARO for which a reasonable estimate of fair value could not be made. The Utility has not recognized a liability related to these additional obligations, which include obligations to restore land to its pre-use condition under the terms of certain land rights agreements, removal and proper disposal of lead-based paint contained in some Utility facilities, removal of certain communications equipment from leased property and retirement activities associated with substation and certain hydroelectric facilities. The Utility was not able to reasonably estimate the ARO associated with these assets because the settlement date of the obligation was indeterminate and information sufficient to reasonably estimate the settlement date or range of settlement dates does not exist. Land rights, communications equipment leases, and substation facilities will be maintained for the foreseeable future, and the Utility cannot reasonably estimate the settlement date or range of settlement dates for the obligations associated with these assets. The Utility does not have information available that specifies which facilities contain lead-based paint and, therefore, cannot reasonably estimate the settlement date(s) associated with the obligation. The Utility will maintain and continue to operate its hydroelectric facilities until operation of a facility becomes uneconomic. The operation of the majority of the Utility’s hydroelectric facilities is currently, and for the foreseeable future, economic and the settlement date cannot be determined at this time.

Impairment of Long-Lived Assets

In accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” (“SFAS No. 144”), PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment, based on projections of undiscounted future cash flows, whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets. In the event this evaluation indicates that such cash flows are not expected to fully recover the assets, the assets are written down to their estimated fair value. No significant impairments were recorded in 2008, 2007, and 2006.

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Unamortized loss on debt extinguishments, net of gain, was approximately \$251 million and \$269 million at December 31, 2008 and 2007, respectively. The Utility's amortization expense related to this loss was approximately \$26 million in 2008 and 2007, and \$27 million in 2006. Deferred gains and losses on debt extinguishments are recorded to Other Noncurrent Assets – Regulatory assets in the Consolidated Balance Sheets.

Gains and losses on debt extinguishments associated with unregulated operations are fully recognized at the time such debt is reacquired and are reported as a component of interest expense.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that result from transactions and other economic events, other than transactions with shareholders. The following table sets forth the after-tax changes in each component of accumulated other comprehensive income (loss):

	Minimum Pension Liability Adjustment	Adoption of SFAS No. 158	Employee Benefit Plan Adjustment in Accordance with SFAS No. 158	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2005	<u>\$ (8)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (8)</u>
Period change in:				
Adoption of SFAS No. 158 (net of income tax benefit of \$8 million)	8	(19)	-	(11)
Balance at December 31, 2006	<u>\$ -</u>	<u>\$ (19)</u>	<u>\$ -</u>	<u>\$ (19)</u>
Period change in pension benefits and other benefits:				
Unrecognized prior service cost (net of income tax expense of \$18 million)	-	-	26	26
Unrecognized net gain (net of income tax expense of \$195 million)	-	-	289	289
Unrecognized net transition obligation (net of income tax expense of \$11 million)	-	-	16	16
Transfer to regulatory account (net of income tax benefit of \$207 million) ⁽¹⁾	-	-	(302)	(302)
Balance at December 31, 2007	<u>\$ -</u>	<u>\$ (19)</u>	<u>\$ 29</u>	<u>\$ 10</u>
Period change in pension benefits and other benefits:				
Unrecognized prior service cost (net of income tax expense of \$27 million)	-	-	37	37
Unrecognized net loss (net of income tax benefit of \$1,088 million)	-	-	(1,583)	(1,583)
Unrecognized net transition obligation (net of income tax expense of \$11 million)	-	-	15	15
Transfer to regulatory account (net of income tax expense of \$894 million) ⁽¹⁾	-	-	1,300	1,300
Balance at December 31, 2008	<u>\$ -</u>	<u>\$ (19)</u>	<u>\$ (202)</u>	<u>\$ (221)</u>

⁽¹⁾ The Utility recorded approximately \$2,259 million in 2008 and \$109 million in 2007, pre-tax, as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71. The adjustment resulted in a regulatory asset balance at December 31, 2008. The Utility recorded approximately \$44 million in 2007, pre-tax, as an addition to the existing pension regulatory liability in accordance with SFAS No. 71. See Note 14 of the Notes to the Consolidated Financial Statements for further information on pre-tax transfer amounts to the regulatory account.

There was no material difference between PG&E Corporation's and the Utility's accumulated other comprehensive income (loss) for the periods presented above.

Revenue Recognition

The Utility's operating revenues are comprised of revenue from electric and natural gas distribution and transmission services and electric generation services. Amounts recorded for these services are billed to the Utility's customers at the CPUC-approved and FERC-approved rates, which provide an authorized rate of return, and recovery of operation and maintenance and capital-related carrying costs. The Utility's revenues are recognized as electricity and natural gas are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 17 of the Notes to the Consolidated Financial Statements, in January 2001, the California Department of Water Resources ("DWR") began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. The Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts the amounts passed through to the DWR from its electricity revenues. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues and from the cost of electricity in its Consolidated Statements of Income.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" ("SFAS No. 109"). Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Investment tax credits are amortized over the life of the related property. See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of income taxes.

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

Nuclear Decommissioning Trusts

The Utility accounts for its investments held in the Nuclear Decommissioning Trusts in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities" ("SFAS No. 115"), as well as FASB Staff Position Nos. 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" ("SFAS Nos. 115-1 and 124-1"). Under SFAS No. 115, the Utility records realized gains and losses as additions and reductions to trust asset balances. In accordance with SFAS Nos. 115-1 and 124-1, the Utility recognizes an impairment of an investment if the fair value of that investment is less than its cost and if the impairment is concluded to be other-than-temporary. (See Note 13 of the Notes to the Consolidated Financial Statements for further discussion.)

Accounting for Derivatives and Hedging Activities

The Utility engages in price risk management activities to manage its exposure to fluctuations in commodity prices. Price risk management activities involve entering into contracts to procure electricity, natural gas, nuclear fuel, and firm transmission rights for electricity.

The Utility uses a variety of energy and financial instruments, such as forward contracts, futures, swaps, options and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. Derivative instruments are recorded in PG&E Corporation's and the Utility's Consolidated Balance Sheets at fair value, unless they qualify for the normal purchase and sales exception. The normal purchase and sales exception requires, among other things, physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business. Changes in the fair value of derivative instruments are recorded in earnings, or to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts. Derivative instruments may be designated as cash flow hedges when they are entered into to hedge variable price risk associated with the purchase of commodities. For cash flow hedges, fair value changes are deferred in accumulated other comprehensive income and recognized in earnings as the hedged transactions occur, unless they are recovered in rates, in which case, they are recorded in regulatory accounts.

In order for a derivative instrument to be designated as a cash flow hedge, the relationship between the derivative instrument and the hedged item or transaction must be highly effective in hedging the exposure to variability in expected future cash flows. The effectiveness test is performed at the inception of the hedge and each reporting period thereafter, throughout the period that the hedge is designated as such. Unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument, to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

Cash flow hedge accounting is discontinued prospectively if it is determined that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If cash flow hedge accounting is discontinued, the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses previously recorded in accumulated other comprehensive income (loss) will remain there until the hedged item is recognized in earnings when it matures or is exercised, unless the forecasted transaction is probable of not occurring, in which case the gains and losses from the derivative instrument will be immediately recognized in earnings. Any gains and losses that would have been recognized in earnings or deferred in accumulated other comprehensive income (loss), to the extent they are recoverable through rates, are deferred and recorded in regulatory accounts.

The fair value of derivative instruments is estimated using various methods including the use of unadjusted prices in active markets to determine the net present value of estimated future cash flows, the mid-point of quoted bid and asked forward prices, including quotes from brokers, and electronic exchanges, supplemented by online price information from news services, and the Black's Option Pricing Model. When market data is not available, proprietary models are used to estimate fair value.

The Utility has derivative instruments for the physical delivery of commodities transacted in the normal course of business, as well as non-financial assets that are not exchange-traded. These derivative instruments are eligible for the normal purchase and sales and non-exchange traded contract exceptions under SFAS No. 133, and are not reflected in the Utility's Consolidated Balance Sheets at fair value. They are recorded and recognized in income under the accrual method of accounting. Therefore, expenses are recognized as incurred.

The Utility has certain commodity contracts for the purchase of nuclear fuel and core gas transportation and storage contracts that are not derivative instruments and are not reflected in the Utility's Consolidated Balance Sheets at fair value. Expenses are recognized as incurred.

See Note 11 of the Notes to the Consolidated Financial Statements.

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157 "Fair Value Measurements" ("SFAS No. 157"), which establishes a fair value hierarchy that prioritizes inputs to valuation techniques used to measure fair value. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or the "exit price." The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. (See Note 12 of the Notes to the Consolidated Financial Statements for further discussion on SFAS No. 157.)

Amendment of FASB Interpretation No. 39

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of FASB Staff Position on FASB Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"). Under FIN 39-1, a reporting entity is required to offset the cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement when reporting those amounts on a net basis. The provisions of FIN 39-1 are applied retrospectively. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion and financial statement impact of the implementation of FIN 39-1.

Fair Value Option

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS No. 159"). SFAS No. 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value with changes in fair value recognized in earnings. PG&E Corporation and the Utility have not elected the fair value option for any assets or liabilities as of and during the three and twelve months ended December 31, 2008; therefore, the adoption of SFAS No. 159 did not impact the Condensed Consolidated Financial Statements.

Disclosure by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities

On December 31, 2008, PG&E Corporation and the Utility adopted the provisions of FASB Staff Position ("FSP") FAS 140-4 and FIN 46R-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" ("FSP FAS 140-4 and FIN 46R-8"). This FSP amends FASB No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities" to require public companies to provide additional qualitative disclosures about transfers of financial assets. This guidance also amended FIN 46R to require public enterprises to provide additional disclosures about their involvement with VIEs when they are the primary beneficiary of the VIE, hold a significant variable interest in the VIE, or are sponsors of and hold a variable interest in the VIE.

Although PG&E Corporation and the Utility were not impacted by the amendment to FASB No. 140 as of December 31, 2008, they were impacted by the amendment to FIN 46R, primarily through the Utility's power purchase agreements which may be considered significant variable interests. Accordingly, when the Utility has a significant variable interest in a VIE, FSP FAS 140-4 and FIN 46R-8 require additional disclosures about the entity, the extent of the Utility's involvement with the entity, and the Utility's methodology for evaluating these entities under FIN 46R. See "Consolidation of Variable Interest Entities" within Note 2 to the Consolidated Financial Statements for expanded disclosures required by FSP FAS 140-4 and FIN 46R-8.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133" ("SFAS No. 161"). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133. An entity is required to provide qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures on fair value amounts of, and gains, and losses on derivative instruments, and disclosures relating to credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective prospectively for fiscal years beginning after November 15, 2008. PG&E Corporation and the Utility will include the expanded disclosure required by SFAS No. 161 in their combined quarterly report on Form 10-Q for the quarter ended March 31, 2009.

Disclosures about Employers' Postretirement Benefit Plan Asset - an amendment to FASB Statement No. 132(R)

In December 2008, the FASB issued FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" ("FSP 132(R)-1"). FSP 132(R)-1 amends and expands the disclosure requirements of SFAS No. 132. An entity is required to provide qualitative disclosures about how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, and the concentration of risk within plan assets. Additionally, quantitative disclosures are required showing the fair value of each major category of plan assets, the levels in which each asset is classified within the fair value hierarchy, and a reconciliation for the period of plan assets which are measured using significant unobservable inputs. FSP 132(R)-1 is effective prospectively for fiscal years ending after December 15, 2009. PG&E Corporation and the Utility are currently evaluating the impact of FSP 132(R)-1.

Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement - an amendment to FASB Statement No. 107 and FASB Statement No. 133

In September 2008, the FASB issued Emerging Issues Task Force ("EITF") 08-5, "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" ("EITF 08-5"). EITF 08-5 clarifies the unit of account in determining the fair value of a liability under SFAS No. 107 "Disclosures about Fair Value of Financial Instruments" or SFAS No. 133 "Accounting for Derivatives and Hedging Activities". Specifically, it requires an entity to incorporate any third-party credit enhancements that are issued with and are inseparable from a debt instrument into the fair value of that debt instrument. EITF 08-5 is effective prospectively for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. PG&E Corporation and the Utility are currently evaluating the impact of EITF 08-5.

Equity Method Investment Accounting Consideration - an amendment to Accounting Principles Board No. 18

In November 2008, the FASB issued Emerging Issues Task Force 08-6, "Equity Method Accounting Considerations" ("EITF 08-6"). EITF 08-6 clarifies the application of equity method accounting under Accounting Principles Board 18, "The Equity Method of Accounting for Investments in Common Stock". Specifically, it requires companies to initially record equity method investments based on the cost accumulation model, precludes separate other-than-temporary impairment tests on an equity method investee's indefinite-lived assets from the investee's test, requires companies to account for an investee's issuance of shares as if the equity method investor had sold a proportionate share of its investment, and requires that an equity method investor continue to apply the guidance in paragraph 19(l) of Opinion 18 upon a change in the investor's accounting from the equity method to the cost method. EITF 08-6 is effective prospectively for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. PG&E Corporation and the Utility are currently evaluating the impact of EITF 08-6.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

The Utility accounts for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations.

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in future rates. The regulatory assets are amortized over future periods consistent with the inclusion of costs in authorized customer rates. If costs that a regulated enterprise expects to incur in the future are currently being recovered through rates, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future must be recorded as regulatory liabilities.

To the extent portions of the Utility's operations cease to be subject to SFAS No. 71, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

Regulatory Assets

Long-Term Regulatory Assets

Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31,	
	2008	2007
Regulatory asset for pension benefits	\$ 1,624	\$ -
Regulatory asset for energy recovery bonds	1,487	1,833
Regulatory assets for deferred income tax	847	732
Utility retained generation regulatory assets	799	947
Environmental compliance costs	385	328
Price risk management	362	20
Unamortized loss, net of gain, on reacquired debt	225	269
Regulatory assets associated with plan of reorganization	99	122
Contract termination costs	82	96
Scheduling coordinator costs	39	90
Other	47	22
Total regulatory assets	<u>\$ 5,996</u>	<u>\$ 4,459</u>

Regulatory asset for pension benefits represents the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be fully recorded to Accumulated other comprehensive income in the Consolidated Balance Sheets in accordance with SFAS No. 158 “Employers’ Accounting Defined Benefit Pension and Other Post Retirement Plans” (“SFAS No. 158”). (See Notes 2 and 14 of the Notes to the Consolidated Financial Statements.) These balances will be charged against expense to the extent that future expenses exceed amounts recoverable for regulatory purposes.

The regulatory asset for energy recovery bonds (“ERBs”), issued by PG&E Energy Recovery Funding LLC (see Note 5 of the Notes to the Consolidated Financial Statements), represents the refinancing of the settlement regulatory asset established under the December 19, 2003 settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility’s Chapter 11 proceeding (“Chapter 11 Settlement Agreement”). (See Note 15 of the Notes to the Consolidated Financial Statements.) The Utility expects to fully recover this asset by the end of 2012.

The regulatory assets for deferred income tax represent deferred income tax benefits previously passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through, as the CPUC requires utilities under its jurisdiction to follow the “flow-through” method of passing certain tax benefits to customers. The “flow-through” method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income taxes related to regulatory assets over periods ranging from 1 to 45 years.

In connection with the Chapter 11 Settlement Agreement in 2004, the Utility recognized a one-time non-cash gain of \$1.2 billion related to the recovery of the Utility’s retained generation regulatory assets. The Utility expects to recover the individual components of these regulatory assets over their respective lives, with a weighted average life of approximately 17 years.

Environmental compliance costs represent the portion of estimated environmental remediation liabilities that the Utility expects to recover in future rates as actual remediation costs are incurred. The Utility expects to recover these costs over the next 30 years.

Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms in excess of one year.

Unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 18 years, and these costs will be fully recovered by 2026.

Regulatory assets associated with the Utility’s plan of reorganization include costs incurred in financing the Utility’s plan of reorganization under Chapter 11 and costs to oversee the environmental enhancement projects of the Pacific Forest and Watershed Stewardship Council, an entity that was established pursuant to the Utility’s plan of reorganization. The Utility expects to recover these costs over the remaining periods ranging from 5 to 30 years, and these costs should be fully recovered by 2034.

Contract termination costs represent amounts that the Utility incurred in terminating a 30-year power purchase agreement. This regulatory asset will be amortized and collected in rates on a straight-line basis through the end of September 2014, the power purchase agreement’s original termination date.

The regulatory asset related to scheduling coordinator costs represents costs that the Utility incurred beginning in 1998 in its capacity as a scheduling coordinator for its then existing wholesale transmission customers. The Utility expects to fully recover the scheduling coordinator costs by the end of the second quarter of 2010.

At December 31, 2008 and 2007 “Other” primarily consisted of regulatory assets relating to asset retirement obligation costs recorded in accordance with GAAP, which are probable of future recovery through the ratemaking process.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the Utility earns a return only on the Utility’s retained generation regulatory assets; unamortized loss, net of gain, on reacquired debt; and regulatory assets associated with the plan of reorganization.

Current Regulatory Assets

At December 31, 2008 and December 31, 2007, the Utility had current regulatory assets of approximately \$355 million and \$131 million, respectively, consisting primarily of the current component of price risk management regulatory assets and the current portion of long-term regulatory assets. Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms of less than one year. Current regulatory assets are included in Prepaid expenses and other in the Consolidated Balance Sheets.

Regulatory Liabilities

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

(in millions)	Balance at December 31,	
	2008	2007
Cost of removal obligation	\$ 2,735	\$ 2,568
Employee benefit plans	-	578
Public purpose programs	259	264
Recoveries in excess of asset retirement obligation	226	573
California Solar Initiative	183	159
Price risk management	81	124
Gateway Generating Station	67	67
Environmental remediation	52	66
Other	54	49
Total regulatory liabilities	<u>\$ 3,657</u>	<u>\$ 4,448</u>

Cost of removal liabilities represent revenues collected for asset removal costs that the Utility expects to incur in the future.

Employee benefit plan regulatory liability represents the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be fully recorded to Accumulated other comprehensive income in the Consolidated Balance Sheets in accordance with SFAS No. 158. (See Notes 2 and 14 of the Notes to the Consolidated Financial Statements.) These balances will be charged against expense to the extent that future expenses exceed amounts recoverable for regulatory purposes.

Public purpose program liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future.

Regulatory liability for recoveries in excess of asset retirement obligation represent timing differences between the recognition of an ARO in accordance with GAAP and the amounts recognized for ratemaking purposes. (See Note 13 of the Notes to the Consolidated Financial Statements.)

California Solar Initiative liabilities represent revenues collected from customers to pay for costs the Utility expects to incur in the future to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties.

Price risk management regulatory liabilities represent the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year.

The Gateway Generating Station (“Gateway”) regulatory liabilities represent future customer benefits associated with acquisition of Gateway as part of a settlement with Mirant Corporation. The associated liability will be amortized over 30 years beginning in January 2009 when Gateway was placed in service.

The insurance recoveries are refunded to customers as a reduction to rates until customers are fully reimbursed for the cost of hazardous substance remediation that has been collected in rates. (See Note 17 of the Notes to the Consolidated Financial Statements.)

“Other” is an aggregate of regulatory liabilities representing amounts collected for future costs.

Current Regulatory Liabilities

As of December 31, 2008 and 2007, the Utility had current regulatory liabilities of approximately \$313 million and \$280 million, respectively, primarily consisting of the current portion of electric transmission wheeling revenue refunds and amounts that the Utility expects to refund to customers for over-collected electric transmission rates. Current regulatory liabilities are included in Current Liabilities — Other in the Consolidated Balance Sheets.

Regulatory Balancing Accounts

The Utility uses revenue regulatory balancing accounts to accumulate differences between revenues and the Utility’s authorized revenue requirements and cost regulatory balancing accounts to accumulate differences between incurred costs and revenues. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The Utility’s current regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility’s customers through authorized rate adjustments within the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next 12 months are included in Other Noncurrent Assets — Regulatory assets and Noncurrent Liabilities — Regulatory liabilities in the Consolidated Balance Sheets. The CPUC does not allow the Utility to offset regulatory balancing account assets against regulatory balancing account liabilities.

Current Regulatory Balancing Accounts

(in millions)	Receivable (Payable)	
	Balance at December 31,	
	2008	2007
Energy resource recovery	\$ 384	\$ 149
Modified transition cost	214	93
Transmission revenue	173	203
Utility generation	164	90
Energy Recovery Bonds	(231)	(274)
Public purpose programs	(264)	(16)
Reliability services	12	(96)
Other	15	(51)
Total regulatory balancing accounts, net	<u>\$ 467</u>	<u>\$ 98</u>

The Utility is generally authorized to recover 100% of its electric fuel and energy procurement costs. The Utility files annual forecasts of purchased power costs that it expects to incur during the following year and rates are set to recover such expected costs. The energy resource recovery account tracks actual electric costs and recoveries of fuel and energy procurement costs, excluding the DWR’s contract costs. The CPUC has established a mechanism to adjust the Utility’s rates whenever the forecasted aggregate over-collections or under-collections of the Utility’s electric procurement costs for the current year exceed 5% of the Utility’s prior year generation revenues, excluding generation revenues for DWR contracts. In accordance with this mechanism, on August 21, 2008, the CPUC approved the Utility’s request to collect from customers the forecasted 2008 end-of-year under-collection of procurement costs, due mainly to rising natural gas costs and lower than forecasted hydroelectric generation. Effective October 1, 2008, customer rates were adjusted to allow the Utility to collect \$645 million in procurement costs through December 2009. On December 30, 2008, the Utility requested that its electric rates be adjusted, effective January 1, 2009, to reflect the revised forecast of electricity prices which are expected to be lower than originally forecasted as a result of lower natural gas prices. The January 1, 2009 rate changes reflect a net decrease of \$101 million in electric revenues versus revenues based on rates effective October 1, 2008.

The modified transition cost balancing account is used to track the recovery of ongoing competition transition costs (“CTC”), primarily consisting of above-market costs associated with power purchase contracts that were being collected in CPUC-approved rates on or before December 20, 1995 (including costs incurred by the Utility with CPUC approval to restructure, renegotiate, or terminate the contracts). The recovery of ongoing CTC can continue for the term of the contract. The amount of above-market costs associated with the eligible power purchase contracts are determined each year in the ERRA forecast proceeding by comparing the ongoing CTC-eligible contract costs to a CPUC-approved market benchmark to determine whether there are stranded costs associated with these contracts.

The transmission revenue balancing account tracks certain electric transmission revenues for recovery from customers. The balance in this account represents the difference between transmission wheeling revenues received by the Utility from the ISO (on behalf of electric transmission wholesale customers) and refunds to customers plus interest.

The utility generation balancing account is used to record and recover the authorized revenue requirements associated with the Utility-owned electric generation, including capital and related non-fuel operating and maintenance expenses.

The balancing account for energy recovery bonds records certain benefits and costs associated with ERBs that are provided to, or received from, customers. In addition, this account ensures that customers receive the benefits of the net amount of energy supplier refunds, claim offsets, and other credits received by the Utility after the second series of ERBs were issued.

The balancing account for public purpose program revenues tracks the recovery of authorized public purpose program revenue requirement and the actual cost of such programs. The public purpose programs primarily consist of the electric energy efficiency programs; low-income energy efficiency programs; research, development, and demonstration programs; and renewable energy programs. The increase in the current balancing account liability balance at December 31, 2008 compared to the December 31, 2007 is due to a refund of approximately \$230 million the Utility received from the California Energy Commission ("CEC"). The refund amount represents unspent renewables program funding collected in previous periods. The program was canceled in the beginning of 2008 and the CEC was instructed to return any unspent program funds to utilities to allow for customer refund. The refund will be returned to customers in 2009 through lower rates.

The balancing account for reliability services is a FERC-mandated balancing account to ensure that the Participating Transmission Owner neither under-recover nor over-recover from customers the Reliability Services costs it is assessed by the California Independent System Operator ("CAISO").

At December 31, 2008, "Other" included the customer energy efficiency ("CEE") incentive account, which records any incentive awards earned by the Utility for implementing CEE programs, and to reflect these earnings in rates. In December 2008, the Utility's shareholders were awarded \$41.5 million for the first interim award relating to 2006 and 2007 of the 2006-2008 energy efficiency programs, which will be collected in 2009 rates. At December 31, 2007, "Other" mainly consisted of the distribution revenue adjustment mechanism account, which records and recovers the authorized distribution revenue requirements and certain other distribution-related authorized costs.

NOTE 4: DEBT

Long-Term Debt

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

(in millions)	December 31,	
	2008	2007
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	\$ 280	\$ 280
Utility		
Senior notes:		
3.60% due 2009	600	600
4.20% due 2011	500	500
6.25% due 2013	400	-
4.80% due 2014	1,000	1,000
5.625% due 2017	700	500
8.25% due 2018	800	-
6.05% due 2034	3,000	3,000
5.80% due 2037	700	700
6.35% due 2038	400	-
Less: current portion	(600)	-
Unamortized discount, net of premium	(22)	(22)
Total senior notes	7,478	6,278

Pollution control bonds:

Series 1996 C, E, F, 1997 B, variable rates ⁽¹⁾ , due 2026 ⁽²⁾	614	614
Series 1996 A, 5.35%, due 2016	200	200
Series 2004 A-D, 4.75%, due 2023	345	345
Series 2005 A-G, variable rates, due 2016 and 2026 ⁽³⁾	-	454
Series 2008 A-D, variable rates ⁽⁴⁾ , due 2016 and 2026 ⁽⁵⁾	309	-
Series 2008 F and G, 3.75% ⁽⁶⁾ , due 2018 and 2026	95	-
Total pollution control bonds	1,563	1,613
Total Utility long-term debt, net of current portion	9,041	7,891
Total consolidated long-term debt, net of current portion	\$ 9,321	\$ 8,171

⁽¹⁾ At December 31, 2008, interest rates on these bonds and the related loans ranged from 0.75% to 1.20%.

⁽²⁾ Each series of these bonds is supported by a separate letter of credit which expires on February 24, 2012. Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series without a credit facility.

⁽³⁾ During 2008, the credit rating of the insurer of these bonds was downgraded or put on review for possible downgrade by several credit agencies, resulting in increased interest rates. To reduce interest expense, the Utility repurchased \$300 million of the 2005 bonds in March 2008 and the remaining \$154 million in April 2008. In September and October 2008, all of these series, except for the Series 2005 E bonds, were refunded through the issuance of the Series 2008 A-D and F and G bonds. See footnotes 4 and 5.

⁽⁴⁾ At December 31, 2008, interest rates on these bonds and the related loans ranged from 0.57% to 0.85%.

⁽⁵⁾ Each series of these bonds is supported by a separate direct-pay letter of credit which expires on October 29, 2011. The Utility may choose to provide a substitute letter of credit for any series of these bonds, subject to a rating requirement.

⁽⁶⁾ These bonds bear interest at 3.75% per year through September 19, 2010, are subject to mandatory tender on September 10, 2010, and may be remarketed in a fixed or variable rate mode.

PG&E Corporation

Convertible Subordinated Notes

At December 31, 2008, PG&E Corporation had outstanding approximately \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,059 shares of PG&E Corporation common stock, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment for significant changes in the number of outstanding shares of PG&E Corporation's common stock. In addition, holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" determined by multiplying the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. During 2008, PG&E Corporation paid approximately \$28 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. On January 15, 2009, PG&E Corporation paid approximately \$7 million of "pass-through dividends."

On January 13, 2009, PG&E Corporation, upon request by an investor, converted \$28 million of Convertible Subordinated Notes into 1,855,865 shares at the conversion price of \$15.09 per share. Total outstanding Convertible Subordinated Notes after the conversion is approximately \$252 million.

In accordance with SFAS No. 133, the dividend participation rights of the Convertible Subordinated Notes are considered to be embedded derivative instruments and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. The payment of "pass-through dividends" is recognized as an operating cash flow in PG&E Corporation's Consolidated Statements of Cash Flows. Changes in the fair value are recognized in PG&E Corporation's Consolidated Statements of Income as a non-operating expense or income (in Other income (expense), net). At December 31, 2008 and December 31, 2007, the total estimated fair value of the dividend participation rights, on a pre-tax basis, was approximately \$42 million and \$62 million, respectively, of which \$28 million and \$25 million, respectively, was classified as a current liability (in Current Liabilities - Other) and \$14 million and \$37 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other) in the accompanying Consolidated Balance Sheets. The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157, resulting in a \$6 million increase in the liability. (See Note 12 of the Notes to the Consolidated Financial Statements for further discussion of the implementation of SFAS No. 157.)

Utility

Senior Notes

At December 31, 2008, the Utility had outstanding approximately \$8.1 billion of senior notes with various interest rates and maturity dates, including the following issuances made during 2008. On March 3, 2008, the Utility issued \$200 million principal amount of 5.625% Senior Notes due November 30, 2017 and \$400 million principal amount of 6.35% Senior Notes due February 15, 2038.

On October 21, 2008 and November 18, 2008, the Utility issued \$600 million and \$200 million principal amount, respectively, of 8.25% Senior Notes due October 15, 2018.

On November 18, 2008, the Utility also issued \$400 million principal amount of 6.25% Senior Notes due December 1, 2013.

The Utility's senior notes are unsecured and rank equally with the Utility's other senior unsecured and unsubordinated debt. Under the indenture for the senior notes, the Utility has agreed that it will not incur secured debt or engage in sales leaseback transactions (except for (1) debt secured by specified liens, and (2) aggregate other secured debt and sales and leaseback transactions not exceeding 10% of the Utility's net tangible assets, as defined in the indenture) unless the Utility provides that the senior notes will be equally and ratably secured.

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank ("CIEDB") have issued various series of tax-exempt pollution control bonds for the benefit of the Utility. Under the pollution control bond loan agreements related to the Series 1996 A bonds, the Series 2004 A-D bonds and the Series 2008 F and G bonds, the Utility is obligated to pay on the due dates an amount equal to the principal, premium, if any, and interest on these bonds to the trustees for these bonds. With respect to the Series 1996 C, E, and F bonds, the Series 1997 B bonds and the Series 2008 A-D bonds, the Utility reimburses the letter of credit providers for their payments to the trustee for these bonds, or if a letter of credit provider fails to pay under its respective letter of credit, the Utility is obligated to pay the principal, premium, if any, and interest on those bonds. All payments on the Series 1996 C, E, and F bonds, the Series 1997 B bonds and the Series 2008 A-D bonds are made through draws on separate direct-pay letters of credit for each series issued by a financial institution.

All of the pollution control bonds financed or refinanced pollution control facilities at the Geysers geothermal power plant ("Geysers Project") or at the Utility's Diablo Canyon nuclear power plant ("Diablo Canyon") were issued as "exempt facility bonds" within the meaning of Section 142(a) of the Internal Revenue Code of 1954, as amended ("Code"). The Utility agrees not to take any action or fail to take any action if any such action or inaction would cause the interest on the bonds to be taxable or to be other than exempt facility bonds.

In 1999, the Utility sold the Geysers Project to Geysers Power Company, LLC pursuant to purchase and sale agreements that state that Geysers Power Company LLC will use the bond-financed facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Code. Although Geysers Power Company, LLC subsequently filed a petition for reorganization under Chapter 11, it assumed the purchase and sale agreements under its Chapter 11 plan of reorganization which became effective on January 31, 2008. The Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed facilities solely as pollution control bonds facilities within the meaning of Section 103(b)(4)(F) of the Code.

The Utility has obtained credit support from insurance companies for the Series 1996 A bonds and the Series 2004 A-D bonds, such that, if the Utility does not pay the principal and interest on any series of these insured bonds, the bond insurer for that series will pay the principal and interest. The Series 2005 E bonds, which are currently held by the Utility, are also insured.

In 2005, the Utility purchased financial guaranty insurance policies to insure the regularly scheduled payments on \$454 million of pollution control bonds series 2005 A through G issued by the CIEDB. Interest rates on these bonds were set at auction every 7 or 35 days. In January 2008, the insurer's credit rating was downgraded or put on review for possible downgrade by several credit agencies. This, in addition to credit issues that impacted the auction rate securities markets, resulted in increases in interest rates for these bonds. To reduce the interest rate expense, the Utility repurchased \$300 million of the bonds in March 2008 and the remaining \$154 million in April 2008. The Utility refunded \$404 million of the bonds, as described below, and anticipates refunding the remaining \$50 million of the bonds in 2009, subject to conditions in the tax-exempt bond market and the liquidity needs of the Utility.

On September 22, 2008, the CIEDB issued \$50 million principal amount of pollution control bonds series F due on November 1, 2026 and \$45 million principal amount of pollution control bonds series G due on December 1, 2018 for the benefit of the Utility. These series of bonds refunded the corresponding related series of 2005 bonds. Both series bear interest at 3.75% per year through September 19, 2010 and are subject to mandatory tender on September 20, 2010 at a price of 100% of the principal amount plus accrued interest. Thereafter, these series of bonds may be remarketed in a fixed or variable rate mode.

On October 29, 2008, the CIEDB issued approximately \$149 million principal amount of pollution control bonds series A and B due on November 1, 2026 and \$160 million principal amount of pollution control bonds series C and D due on December 1, 2016 for the benefit of the Utility. These series of bonds refunded the corresponding related series of 2005 bonds. The bonds bear interest at variable interest rates not to exceed 12% per year. As of December 31, 2008, the interest rate on the bonds ranged from 0.57% to 0.85% and resets weekly.

Repayment Schedule

At December 31, 2008, PG&E Corporation and the Utility's combined aggregate principal repayment amounts of long-term debt are reflected in the table below:

(in millions, except interest rates)	2009	2010	2011	2012	2013	Thereafter	Total
Long-term debt:							
PG&E Corporation							
Average fixed interest rate	-	9.50%	-	-	-	-	9.50%
Fixed rate obligations	-	\$ 280	-	-	-	-	\$ 280
Utility							
Average fixed interest rate	3.60%	3.75%	4.20%	-	6.25%	5.99%	5.71%
Fixed rate obligations	\$ 600	\$ 95	\$ 500	-	\$ 400	\$ 7,145	\$ 8,740
Variable interest rate as of December 31, 2008	-	-	0.75%	0.92%	-	-	0.87%
Variable rate obligations	-	-	\$ 309 ⁽¹⁾	\$ 614 ⁽²⁾	-	-	\$ 923
Total consolidated long-term debt	\$ 600	\$ 375	\$ 809	\$ 614	\$ 400	\$ 7,145	\$ 9,943

⁽¹⁾ These bonds, due in 2016-2026, are backed by a direct-pay letter of credit which expires on October 29, 2011. The bonds will be subject to a mandatory redemption unless the letter of credit is extended or replaced or the issuer consents to the continuation of these series without a credit facility. Accordingly, the bonds have been classified for repayment purposes in 2011.

⁽²⁾ The \$614 million pollution control bonds, due in 2026, are backed by letters of credit which expire on February 24, 2012. The bonds will be subject to a mandatory redemption unless the letters of credit are extended or replaced. Accordingly, the bonds have been classified for repayment purposes in 2012.

Credit Facilities and Short-Term Borrowings

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at December 31, 2008:

(in millions)			At December 31, 2008				
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Revolving credit facility	February 2012	\$ 200 ⁽¹⁾	\$ -	\$ -	\$ -	\$ 200
Utility	Revolving credit facility	February 2012	2,000 ⁽²⁾	287	-	287	1,426
Total credit facilities			\$ 2,200	\$ 287	\$ -	\$ 287	\$ 1,626

⁽¹⁾ Includes a \$50 million sublimit for letters of credit and \$100 million sublimit for "swingline" loans, defined as loans which are made available on a same-day basis and are repayable in full within 30 days.

⁽²⁾ Includes a \$950 million sublimit for letters of credit and \$100 million sublimit for swingline loans.

PG&E Corporation

Revolving credit facility

PG&E Corporation has a \$200 million revolving credit facility with a syndicate of lenders that expires on February 26, 2012. Borrowings under the revolving credit facility and letters of credit may be used for working capital and other corporate purposes. PG&E Corporation can, at any time, repay amounts outstanding in whole or in part. At PG&E Corporation's request and at the sole discretion of each lender, the revolving credit facility may be extended for additional periods. PG&E Corporation has the right to increase, in one or more requests given no more than once a year, the aggregate facility by up to \$100 million provided certain conditions are met. The fees and interest rates PG&E Corporation pays under the revolving credit facility vary depending on the Utility's unsecured debt ratings issued by Standard & Poor's Ratings Service ("S&P") and Moody's Investors Service ("Moody's"). As of December 31, 2008, the commitment from Lehman Brothers Bank, FSB ("Lehman Bank") represented approximately \$13 million, or 7%, of the total borrowing capacity under the revolving credit facility. PG&E Corporation does not expect that Lehman Bank will fund any borrowings or letter of credit draws under the revolving credit facility.

The revolving credit facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's assets and other fundamental changes. In general, the covenants, representations and events of default mirror those in the Utility's revolving credit facility, discussed below. In addition, the revolving credit facility also requires that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of the Utility. At December 31, 2008, PG&E Corporation met both of these tests.

Utility

Revolving credit facility

The Utility has a \$2 billion revolving credit facility with a syndicate of lenders that expires on February 26, 2012. Borrowings under the revolving credit facility and letters of credit are used primarily for liquidity and to provide credit enhancements to counterparties for natural gas and energy procurement transactions. The Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its revolving credit facility so that liquidity from the revolving credit facility is available to repay outstanding commercial paper. As of December 31, 2008, the commitment from Lehman Bank, represented approximately \$60 million, or 3%, of the revolving credit facility. Lehman Bank has failed to fund its portion of borrowings under the revolving credit facility since September 2008 and the Utility does not expect that Lehman Bank will fund any future borrowings or letter of credit draws.

The revolving credit facility includes usual and customary covenants for credit facilities of this type, including covenants limiting liens to those permitted under the senior notes' indenture, mergers, sales of all or substantially all of the Utility's assets and other fundamental changes. In addition, the revolving credit facility also requires that the Utility maintain a debt to capitalization ratio of at most 65% as of the end of each fiscal quarter. At December 31, 2008, the Utility met this ratio test.

Commercial Paper Program

The Utility has a \$1.75 billion commercial paper program, the borrowings from which are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the Utility's revolving credit facility, as described above. The commercial paper may have maturities up to 365 days and ranks equally with the Utility's other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. At December 31, 2008, the average yield was approximately 2.48%.

NOTE 5: ENERGY RECOVERY BONDS AND RATE REDUCTION BONDS

Energy Recovery Bonds

In conjunction with the Chapter 11 Settlement Agreement, the Utility was authorized to recover \$2.2 billion, resulting in a regulatory asset. (See Note 3 of the Notes to the Consolidated Financial Statements.) To lower the cost borne by customers, ERBs were issued to finance the regulatory asset at an interest rate lower than the rate of return allowed on the regulatory asset. In 2005, PG&E Energy Recovery Funding, LLC ("PERF"), a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of \$2.7 billion supported by a dedicated rate component ("DRC"). The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity customers until the ERBs are fully retired. Under the terms of a recovery property servicing agreement, DRC charges are collected by the Utility and remitted to PERF for payment of the bond principal, interest, and miscellaneous expenses associated with the bonds.

The first series of ERBs issued on February 10, 2005 included five classes aggregating approximately \$1.9 billion principal amount with scheduled maturities ranging from September 25, 2006 to December 25, 2012. Interest rates on the remaining four outstanding classes range from 3.87% for the earliest maturing class, to 4.47% for the latest maturing class. The proceeds of the first series of ERBs were paid by PERF to the Utility and were used by the Utility to refinance the remaining unamortized after-tax balance of the settlement regulatory asset. The second series of ERBs, issued on November 9, 2005, included three classes aggregating approximately \$844 million principal amount, with scheduled maturities ranging from June 25, 2009 to December 25, 2012. Interest rates on the three classes range from 4.85% for the earliest maturing class to 5.12% for the latest maturing class. The proceeds of the second series of ERBs were paid by PERF to the Utility to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC charges from customers.

The total amount of ERB principal outstanding was \$1.6 billion at December 31, 2008 and \$1.9 billion at December 31, 2007. The scheduled principal repayments for ERBs are reflected in the table below:

(in millions)	2009	2010	2011	2012	Total
Utility					
Average fixed interest rate	4.36%	4.49%	4.59%	4.66%	4.53%
Energy recovery bonds	\$ 370	\$ 386	\$ 404	\$ 423	\$ 1,583

While PERF is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF are not available to creditors of the Utility or PG&E Corporation, and the recovery property is not legally an asset of the Utility or PG&E Corporation.

Rate Reduction Bonds

In December 1997, PG&E Funding LLC, a limited liability corporation wholly owned by and consolidated with the Utility, issued \$2.9 billion of rate reduction bonds ("RRBs"). The proceeds of the RRBs were used by PG&E Funding LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers. The RRBs were paid in full when they matured on December 26, 2007 and there are no future principal or interest payments.

NOTE 6: DISCONTINUED OPERATIONS

National Energy & Gas Transmission, Inc. ("NEGT") was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. NEGT filed a voluntary petition for relief under Chapter 11 on July 8, 2003. On October 29, 2004, NEGT's plan of reorganization became effective ("effective date"), at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. PG&E Corporation ceased including NEGT and its subsidiaries in its consolidated income tax returns beginning October 29, 2004. PG&E Corporation will continue to report resolution of NEGT matters in discontinued operations.

On the effective date, PG&E Corporation recorded a net of tax gain on disposal of NEGT of \$684 million. On October 28, 2008, PG&E Corporation resolved 2001-2004 audits with the Internal Revenue Service ("IRS") and recognized after-tax income of approximately \$257 million in the fourth quarter of 2008, of which \$154 million was related to NEGT and recorded as income from discontinued operations. See Note 10 of the Notes to the Consolidated Financial Statements for further discussion of the resolution of the 2001-2004 audits.

At December 31, 2008 and 2007, PG&E Corporation's Consolidated Balance Sheets included the following assets and liabilities related to NEGT:

(in millions)	2008	2007
Current Assets		
Income taxes receivable	\$ 137	\$ 33
Current Liabilities		
Income taxes payable	-	-
Other	10	11
Noncurrent Liabilities		
Income taxes payable	3	74
Deferred income taxes	7	34
Other	12	14

NOTE 7: COMMON STOCK

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 362,346,685 shares were issued and outstanding at December 31, 2008 and 379,646,276 shares were issued and outstanding at December 31, 2007. At December 31, 2007, Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, held 24,665,500 shares of PG&E Corporation common stock. Effective August 29, 2008, Elm Power Corporation was dissolved, and the shares subsequently cancelled.

Of the 362,346,685 shares issued and outstanding at December 31, 2008, 1,287,569 shares were granted as restricted stock as share-based compensation awarded under the PG&E Corporation Long-Term Incentive Program and the 2006 Long-Term Incentive Plan ("2006 LTIP") and 6,876,919 shares were issued upon the exercise of employee stock options, for the account of 401(k) plan participants, and for the Dividend Reinvestment and Stock Purchase Plan. (See Note 14 of the Notes to the Consolidated Financial Statements.)

Utility

The Utility is authorized to issue 800 million shares of its \$5 par value common stock, of which 264,374,809 shares were issued and outstanding as of December 31, 2008 and 282,916,485 shares were issued and outstanding as of December 31, 2007. At December 31, 2007, PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, held 19,481,213 shares of the Utility common stock. Effective August 29, 2008, PG&E Holdings, LLC, was dissolved, and the shares subsequently cancelled. As of December 31, 2008, PG&E Corporation held all of the Utility's outstanding common stock.

The Utility may pay common stock dividends and repurchase its common stock, provided that cumulative preferred dividends on its preferred stock are paid.

Dividends

During 2008, the Utility paid common stock dividends totaling \$589 million, including \$568 million of common stock dividends paid to PG&E Corporation and \$21 million of common stock dividends paid to PG&E Holdings, LLC.

During 2008, PG&E Corporation paid common stock dividends of \$1.53 per share, totaling \$573 million, including \$28 million that was paid to Elm Power Corporation. On December 17, 2008, the Board of Directors of PG&E Corporation declared a dividend of \$0.39 per share, totaling \$141 million, which was paid on January 15, 2009 to shareholders of record on December 31, 2008.

During 2007, the Utility paid common stock dividends of \$547 million. Approximately \$509 million of common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. During 2007, PG&E Corporation paid common stock dividends of \$1.41 per share totaling \$529 million, including approximately \$35 million that was paid to Elm Power Corporation.

During 2006, the Utility paid common stock dividends of \$494 million. Approximately \$460 million of common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. During 2006, PG&E Corporation paid common stock dividends of \$1.32 per share, totaling \$489 million, including approximately \$33 million that was paid to Elm Power Corporation.

PG&E Corporation and the Utility record common stock dividends declared to Reinvested earnings.

NOTE 8: PREFERRED STOCK

PG&E Corporation has authorized 85 million shares of preferred stock, which may be issued as redeemable or nonredeemable preferred stock. No preferred stock of PG&E Corporation has been issued.

Utility

The Utility has authorized 75 million shares of \$25 par value preferred stock and 10 million shares of \$100 par value preferred stock. The Utility specifies that 5,784,825 shares of the \$25 par value preferred stock authorized are designated as nonredeemable preferred stock without mandatory redemption provisions. The remainder of the 75 million shares of \$25 par value preferred stock and the 10 million shares of \$100 par value preferred stock may be issued as redeemable or nonredeemable preferred stock.

At December 31, 2008 and 2007, the Utility had issued and outstanding 5,784,825 shares of nonredeemable \$25 par value preferred stock without mandatory redemption provisions. Holders of the Utility's 5.0%, 5.5%, and 6.0% series of nonredeemable \$25 par value preferred stock have rights to annual dividends ranging from \$1.25 to \$1.50 per share.

At December 31, 2008 and 2007, the Utility had issued and outstanding 4,534,958 shares of redeemable \$25 par value preferred stock without mandatory redemption provisions. The Utility's redeemable \$25 par value preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2008, annual dividends ranged from \$1.09 to \$1.25 per share and redemption prices ranged from \$25.75 to \$27.25 per share.

The last of the Utility's redeemable \$25 par value preferred stock with mandatory redemption provisions was redeemed on May 31, 2005. Currently the Utility does not have any shares of the \$100 par value preferred stock with or without mandatory redemption provisions outstanding.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. During the years ended December 31, 2008, 2007, and 2006, the Utility paid approximately \$14 million of dividends on preferred stock without mandatory redemption provisions. On December 17, 2008, the Board of Directors of the Utility declared a cash dividend on its outstanding series of preferred stock totaling approximately \$3 million that was paid on February 15, 2009 to shareholders of record on January 30, 2009. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

NOTE 9: EARNINGS PER SHARE

Earnings per common share ("EPS") is calculated utilizing the "two-class" method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the "two-class" method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's Convertible Subordinated Notes are entitled to receive pass-through dividends and meet the criteria of a participating security. All PG&E Corporation's participating securities participate on a 1:1 basis with shares of common stock.

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 accordance with SFAS No. 128, "Earnings Per Share" ("SFAS No. 128"). Under SFAS No. 128, PG&E Corporation is required to assume that shares underlying stock options, other stock-based compensation, and warrants are issued and that the proceeds received by PG&E Corporation from exercise of these options and warrants are assumed to be used to purchase common shares at the average market price during the reported period. The incremental shares, the difference between the number of shares assumed issued upon exercise and the number of shares assumed purchased is included in weighted average common shares outstanding for the purpose of calculating diluted EPS.

The following is a reconciliation of PG&E Corporation's net income and weighted average shares of common stock outstanding for calculating basic and diluted net income per share:

(in millions, except per share amounts)	Year ended December 31,		
	2008	2007	2006
Net Income	\$ 1,338	\$ 1,006	\$ 991
Less: distributed earnings to common shareholders	560	508	460
Undistributed earnings	778	498	531
Less: undistributed earnings from discontinued operations	154	-	-
Undistributed earnings from continuing operations	<u>\$ 624</u>	<u>\$ 498</u>	<u>\$ 531</u>
Common shareholders earnings			
Basic			
Distributed earnings to common shareholders	\$ 560	\$ 508	\$ 460
Undistributed earnings allocated to common shareholders - continuing operations	592	472	503
Undistributed earnings allocated to common shareholders - discontinued operations	146	-	-
Total common shareholders earnings, basic	<u>\$ 1,298</u>	<u>\$ 980</u>	<u>\$ 963</u>
Diluted			
Distributed earnings to common shareholders	\$ 560	\$ 508	\$ 460
Undistributed earnings allocated to common shareholders - continuing operations	593	473	504
Undistributed earnings allocated to common shareholders - discontinued operations	146	-	-
Total common shareholders earnings, diluted	<u>\$ 1,299</u>	<u>\$ 981</u>	<u>\$ 964</u>
Weighted average common shares outstanding, basic	357	351	346
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	<u>376</u>	<u>370</u>	<u>365</u>
Weighted average common shares outstanding, basic	357	351	346
Employee share-based compensation and accelerated share repurchases ⁽¹⁾	1	2	3
Weighted average common shares outstanding, diluted	<u>358</u>	<u>353</u>	<u>349</u>
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	<u>377</u>	<u>372</u>	<u>368</u>
Net earnings per common share, basic			
Distributed earnings, basic ⁽²⁾	\$ 1.57	\$ 1.45	\$ 1.33
Undistributed earnings - continuing operations, basic	1.66	1.34	1.45
Undistributed earnings - discontinued operations, basic	0.41	-	-
Total	<u>\$ 3.64</u>	<u>\$ 2.79</u>	<u>\$ 2.78</u>
Net earnings per common share, diluted			
Distributed earnings, diluted	\$ 1.56	\$ 1.44	\$ 1.32
Undistributed earnings - continuing operations, diluted	1.66	1.34	1.44
Undistributed earnings - discontinued operations, diluted	0.41	-	-
Total	<u>\$ 3.63</u>	<u>\$ 2.78</u>	<u>\$ 2.76</u>

⁽¹⁾ Includes approximately one million shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchase agreements (ASRs) for 2006. The remaining shares of approximately two million at December 31, 2006 relate to share-based compensation and are deemed to be outstanding under SFAS No. 128 for the purpose of calculating EPS. PG&E Corporation has no remaining obligation under these ASRs as of December 31, 2007.

⁽²⁾ "Distributed earnings, basic" differs from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual number of, shares outstanding.

PG&E Corporation stock options to purchase 11,935 and 7,285 shares were excluded from the computation of diluted EPS for 2008 and 2007, respectively, because the exercise prices of these options were greater than the average market price of PG&E Corporation common stock during these years. All PG&E Corporation stock options were included in the computation of diluted EPS for 2006 because the exercise price of these stock options was lower than the average market price of PG&E Corporation common stock during the year.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted EPS.

NOTE 10: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

(in millions)	PG&E Corporation			Utility		
	Year Ended December 31,					
	2008	2007	2006	2008	2007	2006
Current:						
Federal	\$ (268)	\$ 526	\$ 743	\$ (188)	\$ 563	\$ 771
State	33	140	201	24	149	210
Deferred:						
Federal	604	(81)	(286)	596	(92)	(276)
State	62	(40)	(98)	62	(43)	(97)
Tax credits, net	(6)	(6)	(6)	(6)	(6)	(6)
Income tax expense	\$ 425	\$ 539	\$ 554	\$ 488	\$ 571	\$ 602

The following describes net deferred income tax liabilities:

(in millions)	PG&E Corporation		Utility	
	Year Ended December 31,			
	2008	2007	2008	2007
Deferred income tax assets:				
Customer advances for construction	\$ 199	\$ 143	\$ 199	\$ 143
Reserve for damages	130	173	129	173
Environmental reserve	225	172	225	172
Compensation	339	162	306	129
Other	231	289	201	261
Total deferred income tax assets	\$ 1,124	\$ 939	\$ 1,060	\$ 878
Deferred income tax liabilities:				
Regulatory balancing accounts	\$ 1,425	\$ 1,219	\$ 1,425	\$ 1,219
Property related basis differences	2,819	2,290	2,813	2,293
Income tax regulatory asset	345	298	345	298
Unamortized loss on reacquired debt	102	110	102	110
Other	81	75	81	66
Total deferred income tax liabilities	\$ 4,772	\$ 3,992	\$ 4,766	\$ 3,986
Total net deferred income tax liabilities	\$ 3,648	\$ 3,053	\$ 3,706	\$ 3,108
Classification of net deferred income tax liabilities:				
Included in current liabilities	\$ 251	\$ -	\$ 257	\$ 4
Included in noncurrent liabilities	3,397	3,053	3,449	3,104
Total net deferred income tax liabilities	\$ 3,648	\$ 3,053	\$ 3,706	\$ 3,108

The differences between income taxes and amounts calculated by applying the federal statutory rate to income before income tax expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2008	2007	2006	2008	2007	2006
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	3.1	4.2	4.3	3.3	4.3	4.6
Effect of regulatory treatment of fixed asset differences	(3.2)	(3.0)	(1.2)	(3.1)	(2.9)	(1.1)
Tax credits, net	(0.5)	(0.7)	(0.6)	(0.5)	(0.7)	(0.6)
IRS Audit Settlements	(7.1)	-	-	(4.1)	-	-
Other, net	(0.9)	(0.6)	(1.6)	(1.7)	0.1	0.1
Effective tax rate	26.4 %	34.9 %	35.9 %	28.9 %	35.8 %	38.0 %

On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). Under FIN 48, a tax benefit can be recognized only if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to FIN 48 represents an unrecognized tax benefit. An unrecognized tax benefit is a liability that represents a potential future obligation to the taxing authority.

The following table reconciles the changes in unrecognized tax benefits during 2008 and 2007:

	PG&E Corporation	Utility
(in millions)		
Balance at January 1, 2007	\$ 212	\$ 90
Additions for tax position of prior years	15	4
Reductions for tax position of prior years	(18)	-
Balance at December 31, 2007	\$ 209	\$ 94
Additions for tax position of prior years	43	20
Decreases as a result of settlements with the IRS	(177)	(77)
Balance at December 31, 2008	<u>\$ 75</u>	<u>\$ 37</u>

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2008 for PG&E Corporation and the Utility is \$46 million and \$24 million, respectively.

PG&E Corporation and the Utility recognized a reduction in interest and penalties expense on unrecognized tax benefits by \$44 million and \$21 million, respectively, as of December 31, 2008. PG&E Corporation and the Utility recognized interest and penalties expense on unrecognized tax benefits of \$7 million and \$2 million, respectively, as of December 31, 2007. Interest and penalties expense is classified as Income tax provision in the Consolidated Statements of Income. Interest and penalties expense included in the liability for uncertain tax position was \$11 million and \$2 million, respectively, at December 31, 2008, and \$55 million and \$22 million, respectively, at December 31, 2007.

PG&E Corporation and the Utility do not expect the company's total amount of unrecognized tax benefits to change significantly within the next 12 months.

On July 9, 2008, PG&E Corporation was notified that the U.S. Congress' Joint Committee on Taxation ("Joint Committee") had approved a settlement reached with the IRS appellate division in the first quarter of 2007 for tax years 1997 through 2000. As a result of the settlement, PG&E Corporation received a \$16 million refund from the IRS in October 2008. This settlement did not result in material changes to the amount of unrecognized tax benefits that PG&E Corporation recorded under FIN 48.

On June 20, 2008, PG&E Corporation reached an agreement with the IRS regarding a change in accounting method related to the capitalization of indirect service costs for tax years 2001 through 2004. This agreement resulted in a \$29 million benefit from a reduction in interest expense accrued on unrecognized tax benefits partially offset by a \$15 million liability associated with unrecognized state tax benefits, for a net tax benefit of approximately \$14 million. In addition, on June 27, 2008, PG&E Corporation agreed to the revenue agent reports (“RARs”) from the IRS that reflected this agreement and resolved 2001 through 2004 audit issues. The RARs for the 2001 through 2004 audit years were submitted to the Joint Committee for approval.

On October 28, 2008, the IRS executed a closing agreement for the 2001 through 2004 years audit after the Joint Committee indicated it took no exception to the settlement. As a result of the settlement, PG&E Corporation recognized after-tax income of approximately \$257 million, including interest, in the fourth quarter of 2008, of which approximately \$154 million was related to NEGТ and recorded as income from discontinued operations, and approximately \$60 million was attributable to the Utility. PG&E Corporation expects to receive a tax refund from the IRS of approximately \$310 million, plus interest, as a result of the settlement, of which approximately \$170 million will be allocated to the Utility. The after-tax income of \$257 million includes approximately \$204 million primarily related to a reduction in PG&E Corporation’s unrecognized tax benefits and additional claims allowed, and approximately \$53 million related to the utilization of federal capital loss carry forwards.

On December 24, 2008, PG&E Corporation filed claims with the California Franchise Tax Board to reduce tax on income related to generator settlements from 2004 through 2007. As a result of the claims, the Utility recorded a tax benefit of \$16 million in the fourth quarter 2008.

On January 30, 2009, PG&E Corporation reached a tentative agreement with the IRS to resolve refund claims related to the 1998 and 1999 tax years that, if approved by the Joint Committee, would result in a cash refund of approximately \$200 million, plus interest. The refund would result in net income of approximately \$50 million. Because the agreement is subject to Joint Committee approval, PG&E Corporation has not recognized any benefit associated with the potential refund.

As of December 31, 2008, PG&E Corporation had \$68 million of federal capital loss carry forwards based on tax returns as filed, of which approximately \$30 million will expire if not used by tax year 2009.

The IRS is currently auditing tax years 2005 through 2007. For tax year 2008, PG&E Corporation has been participating in the IRS’ Compliance Assurance Process (“CAP”), a real-time audit process intended to expedite the resolution of issues raised during audits. To date, no material adjustments have been proposed for either the 2005 through 2007 audit or for the 2008 CAP, except for adjustments to reflect rollover impact of items settled from prior audits.

The California Franchise Tax Board is currently auditing PG&E Corporation’s 2004 and 2005 combined California income tax returns. To date, no material adjustments have been proposed. In addition to the federal capital loss carry forwards, PG&E Corporation has \$2.1 billion of California capital loss carry forwards based on tax returns as filed, the majority of which expired in tax year 2008.

NOTE 11: DERIVATIVES AND HEDGING ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel, and firm electricity transmission rights, some of which meet the definition of a derivative under SFAS No. 133. These contracts include physical and financial instruments, such as forwards, futures, swaps, options, and other instruments and agreements and are primarily intended to reduce the volatility in the cost of electricity, natural gas, nuclear fuel, and firm electricity transmission rights. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes.

The Utility also has derivative instruments for the physical delivery of commodities transacted in the normal course of business. These derivative instruments are eligible for the normal purchase and sales exception under SFAS No. 133, where physical delivery is probable, in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and where the price is not tied to an unrelated underlying. Instruments that are eligible for the normal purchase and sales exception are not reflected in the Consolidated Balance Sheets.

All such derivative instruments, including instruments designated as cash flow hedges, are recorded at fair value and presented as price risk management assets and liabilities in the Consolidated Balance Sheets (see table below). As a result of applying the provisions of SFAS No. 71, unrealized changes in the fair value of derivative instruments are deferred and recorded to regulatory assets or liabilities. Under the same regulatory accounting treatment, changes in the fair value of cash flow hedges are also recorded to regulatory assets or liabilities, rather than being deferred in accumulated other comprehensive income.

In PG&E Corporation and the Utility’s Consolidated Balance Sheets, price risk management assets and liabilities associated with the Utility’s electricity and gas procurement activities are presented on a net basis by counterparty where the right of offset exists. As PG&E Corporation and the Utility adopted the provisions of FIN 39-1 on January 1, 2008, the net balances include outstanding cash collateral associated with derivative positions. (See Note 2 of the Notes to the Consolidated Financial Statements for discussion of the adoption of FIN 39-1.) The table below shows the total price risk management derivative balances and the portions that are designated as cash flow hedges as of December 31, 2008:

(in millions)	Price Risk Management Derivatives Balance at December 31, 2008			
	Derivatives with No Hedge Designation	Designated as Cash Flow Hedges	Cash Collateral	Total Price Risk Management Derivatives
Current Assets – Prepaid expenses and other	\$ 55	\$ -	\$ 55	\$ 110
Other Noncurrent Assets – Other	81	-	67	148
Current Liabilities – Other	132	139	(75)	196
Noncurrent Liabilities – Other	150	211	(69)	292

The table below shows the total price risk management derivative balances and the portions that are designated as cash flow hedges as of December 31, 2007:

(in millions)	Price Risk Management Derivatives Balance at December 31, 2007			
	Derivatives with No Hedge Designation	Designated as Cash Flow Hedges	Cash Collateral ⁽²⁾	Total Price Risk Management Derivatives
Current Assets – Prepaid expenses and other	\$ 54	\$ (2) ⁽¹⁾	\$ 3	\$ 55
Other Noncurrent Assets – Other	83	42	46	171
Current Liabilities – Other	71	12	(16)	67
Noncurrent Liabilities – Other	17	3	-	20

⁽¹⁾ \$2 million of the cash flow hedges in a liability position at December 31, 2007 related to counterparties for which the total net derivatives position is a current asset.

⁽²⁾ The net cash collateral receivable balance was classified as Current Assets – Prepaid expenses and other in the 2007 Annual Report. Amounts have been reclassified in accordance with FIN 39-1.

As of December 31, 2008, PG&E Corporation and the Utility had cash flow hedges with expiration dates through December 2012 for energy contract derivative instruments.

Upon settlement of derivative instruments, including those derivative instruments for which the normal purchase and sales exception has been elected and derivative instruments designated as cash flow hedges, any gains or losses are recorded in the cost of electricity and the cost of natural gas. All costs of electricity and natural gas are passed through to customers. Cash inflows and outflows associated with the settlement of price risk management transactions are recognized in operating cash flows on PG&E Corporation and the Utility's Consolidated Statements of Cash Flows.

The dividend participation rights of PG&E Corporation's Convertible Subordinated Notes, considered to be derivative instruments, are recorded at fair value in PG&E Corporation's Consolidated Financial Statements in accordance with SFAS No. 133. The dividend participation rights are not considered price risk management instruments, thus are not included in the tables above. (See Note 4 of the Notes to the Consolidated Financial Statements for discussion of the Convertible Subordinated Notes.)

NOTE 12: FAIR VALUE MEASUREMENTS

On January 1, 2008, PG&E Corporation and the Utility adopted the provisions of SFAS No. 157, which defines fair value measurements and implements a hierarchical disclosure requirement. SFAS No. 157 deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 defines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date," or the "exit price." Accordingly, an entity must determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability, not those of the reporting entity itself. The identification of market participant assumptions provides a basis for determining what inputs are to be used for pricing each asset or liability. Additionally, SFAS No. 157 establishes a fair value hierarchy that gives precedence to fair value measurements calculated using observable inputs over those using unobservable inputs. Accordingly, the following levels were established for each input:

Level 1: "Inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date." Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments classified as Level 1 consist of financial instruments such as exchange-traded derivatives (other than options), listed equities, and U.S. government treasury securities.

Level 2: "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly." Instruments classified as Level 2 consist of financial instruments such as non-exchange-traded derivatives (other than options) valued using exchange inputs and exchange-traded derivatives (other than options) for which the market is not active.

Level 3: "Unobservable inputs for the asset or liability." These are inputs for which there is no market data available, or observable inputs that are adjusted using Level 3 assumptions. Instruments classified as Level 3 consist primarily of financial and physical instruments such as options, non-exchange-traded derivatives valued using broker quotes, and new and/or complex instruments that have immature or limited markets.

SFAS No. 157 is applied prospectively with limited exceptions. One such exception relates to SFAS No. 157's nullification of a portion of EITF No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" ("EITF 02-3"). Prior to the issuance of SFAS No. 157, EITF 02-3 prohibited an entity from recognizing a day one gain or loss on derivative contracts based on the use of unobservable inputs. A day one gain or loss is the difference between the transaction price and the fair value of the contract on the day the derivative contract is executed (i.e., at inception). Prior to the adoption of SFAS No. 157, the Utility did not record any day one gains associated with Congestion Revenue Rights ("CRRs") as the fair value was based primarily on unobservable market data. (CRRs allow market participants, including load serving entities, to hedge the financial risk of congestion charges imposed by the CAISO in the day-ahead market to be established when the CAISO's Market Redesign and Technology Upgrade ("MRTU") becomes effective.) The costs associated with procuring CRRs are currently being recovered in rates or are probable of recovery in future rates. The adoption of SFAS No. 157 permitted the Utility to record day one gains associated with CRRs resulting in a \$48 million increase in price risk management assets and the related regulatory liabilities as of January 1, 2008.

The following table sets forth the fair value hierarchy by level of PG&E Corporation and the Utility's recurring fair value financial instruments as of December 31, 2008. The instruments are classified based on the lowest level of input that is significant to the fair value measurement. PG&E Corporation and the Utility's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

PG&E Corporation				
Fair Value Measurements as of December 31, 2008				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments (held by PG&E Corporation)	\$ 164	\$ -	\$ 12	\$ 176
Nuclear decommissioning trusts ⁽¹⁾	1,505	289	5	1,799
Rabbi trusts	66	-	-	66
Long-term disability trust	99	-	78	177
Assets Total	\$ 1,834	\$ 289	\$ 95	\$ 2,218
Liabilities:				
Dividend participation rights	\$ -	\$ -	\$ 42	\$ 42
Price risk management instruments ⁽²⁾	(49)	123	156	230
Other	-	-	2	2
Liabilities Total	\$ (49)	\$ 123	\$ 200	\$ 274

⁽¹⁾ Excludes taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$159 million to Level 1, \$32 million to Level 2, and \$76 million to Level 3.

Utility				
Fair Value Measurements as of December 31, 2008				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trusts ⁽¹⁾	\$ 1,505	\$ 289	\$ 5	\$ 1,799
Long term disability trust	99	-	78	177
Assets Total	\$ 1,604	\$ 289	\$ 83	\$ 1,976
Liabilities:				
Price risk management instruments ⁽²⁾	(49)	123	156	230
Other	-	-	2	2
Liabilities Total	\$ (49)	\$ 123	\$ 158	\$ 232

⁽¹⁾ Excludes taxes on appreciation of investment value.

⁽²⁾ Balances include the impact of netting adjustments in accordance with the requirements of FIN 39-1 of \$159 million to Level 1, \$32 million to Level 2, and \$76 million to Level 3.

PG&E Corporation and the Utility's fair value measurements incorporate various factors required under SFAS No. 157 such as the credit standing of the counterparties involved, nonperformance risk including the risk of nonperformance by PG&E Corporation and the Utility on their liabilities, the applicable exit market, and specific risks inherent in the instrument. Nonperformance and credit risk adjustments on the Utility's price risk management instruments are based on current market inputs when available, such as credit default swap spreads. When such information is not available, internal models may be used. As of December 31, 2008, the nonperformance and credit risk adjustment represents approximately 5% of the net price risk management value. As permitted under SFAS No. 157, PG&E Corporation and the Utility utilize a mid-market pricing convention (the mid-point between bid and ask prices) as a practical expedient in valuing the majority of its derivative assets and liabilities at fair value.

Money Market Investments

PG&E Corporation invests in AAA-rated money market funds that seek to maintain a stable net asset value. These funds invest in high quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued based on observable inputs such as expected yield and credit quality and are thus classified as Level 1 instruments. Approximately \$164 million held in money market funds are recorded as Cash and cash equivalents in PG&E Corporation's Consolidated Balance Sheets.

As of December 31, 2008, PG&E Corporation classified approximately \$12 million invested in one money market fund as a Level 3 instrument because the fund manager imposed restrictions on fund participants' redemption requests. PG&E Corporation's investment in this money market fund, previously recorded as Cash and cash equivalents, is recorded as Prepaid expenses and other in PG&E Corporation's Consolidated Balance Sheets.

Trust Assets

The nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust hold primarily equities, debt securities, mutual funds, and life insurance policies. These instruments are generally valued based on unadjusted prices in active markets for identical transactions or unadjusted prices in active markets for similar transactions. The rabbi trusts are classified as Current Assets-Prepaid expenses and other and Other Noncurrent Assets-Other in PG&E Corporation's Consolidated Balance Sheets. The long-term disability trust is classified as Current Liabilities-Other in PG&E Corporation and the Utility's Consolidated Balance Sheets, representing a net obligation as the projected obligation exceeds plan assets.

The Consolidated Balance Sheets of PG&E Corporation and the Utility contain assets held in trust for the PG&E Retirement Plan Master Trust, the Postretirement Life Insurance Trust, and the Postretirement Medical Trusts presented on a net basis. The assets held in these trusts are fair valued annually and are included in the scope of SFAS No. 157, but the pension liabilities are not considered fair value instruments under SFAS No. 157. As the assets are presented net of a non-fair value measure in PG&E Corporation and the Utility's Consolidated Financial Statements, the fair value hierarchy disclosure in the table above does not require the inclusion of pension assets. The pension assets include equities, debt securities, swaps, commingled funds, futures, cash equivalents, and insurance policies. The pension assets are presented net of pension obligations as Noncurrent Liabilities - Other in PG&E Corporation and the Utility's Consolidated Balance Sheets.

Price Risk Management Instruments

Price risk management instruments are comprised of physical and financial derivative contracts including futures, forwards, options, and swaps that are both exchange-traded and over-the-counter ("OTC") traded contracts. PG&E Corporation and the Utility consistently apply valuation methodology among their instruments. SFAS No. 71 allows the Utility to defer the unrealized gains and losses associated with these derivatives, as they are expected to be refunded or recovered in future rates.

All energy options (exchange-traded and OTC) are valued using the Black's Option Pricing Model and classified as Level 3 measurements primarily due to volatility inputs.

CRRs allow market participants, including load serving entities, to hedge financial risk of CAISO-imposed congestion charges in the day-ahead market to be established when MRTU becomes effective. Firm Transmission Rights ("FTRs") allow market participants, including load serving entities to hedge both the physical and financial risk associated with CAISO-imposed congestion charges until the MRTU becomes effective. The Utility's demand response contracts ("DRs") with third party aggregators of retail electricity customers contain a call option entitling the Utility to require that the aggregator reduce electric usage by the aggregator's customers at times of peak energy demand or in response to a CAISO alert or other emergency. As the market for CRRs, FTRs, and DRs have minimal activity, observable inputs may not be available in pricing these instruments. Therefore, the pricing models used to value these instruments often incorporate significant estimates and assumptions that market participants would use in pricing the instrument. Accordingly, they are classified as Level 3 measurements. When available, observable market data is used to calibrate pricing models.

Exchange-traded derivative instruments (other than options) are generally valued based on unadjusted prices in active markets using pricing models to determine the net present value of estimated future cash flows. Accordingly, a majority of these instruments are classified as Level 1 measurements. However, certain of these exchange-traded contracts are classified as Level 2 measurements because the contract term extends to a point at which the market is no longer considered active but where prices are still observable. This determination is based on an analysis of the relevant characteristics of the market such as trading hours, trading volumes, frequency of available quotes, and open interest. In addition, a number of OTC contracts have been valued using unadjusted exchange prices in active markets. Such instruments are classified as Level 2 measurements as they are not exchange-traded instruments. The remaining OTC derivative instruments are valued using pricing models based on the net present value of estimated future cash flows based on broker quotations. Such instruments are generally classified within Level 3 of the fair value hierarchy as broker quotes are only indicative of market activity and do not necessarily reflect binding offers to transact.

See Note 11 of the Notes to the Consolidated Financial Statements for further discussion of the price risk management instruments.

Dividend Participation Rights

The dividend participation rights of the Convertible Subordinated Notes are embedded derivative instruments in accordance with SFAS No. 133 and, therefore, are bifurcated from Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Balance Sheets. The dividend participation rights are valued based on the net present value of estimated future cash flows using internal estimates of future common stock dividends. The fair value of the dividend participation rights is recorded as Current Liabilities-Other and Noncurrent Liabilities-Other in PG&E Corporation's Consolidated Balance Sheets. (See Note 4 of the Notes to the Consolidated Financial Statements for further discussion of these instruments.)

Debt Instruments

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

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values as of December 31, 2008 and 2007.
- The fair values of the Utility's fixed rate senior notes, fixed rate pollution control bond loan agreements, and the ERBs issued by PG&E Energy Recovery Funding LLC, were based on quoted market prices obtained from the Bloomberg financial information system at December 31, 2008.
- The estimated fair value of PG&E Corporation's 9.50% Convertible Subordinated Notes was determined by considering the prices of securities displayed as of the close of business on December 31, 2008 by a proprietary bond trading system which tracks and marks a broad universe of convertible securities including the securities being assessed.

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented at their carrying value in the Consolidated Balance Sheets):

(in millions)	At December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	\$ 280	\$ 739	\$ 280	\$ 849
Utility	8,740	9,134	6,823	6,701
Energy recovery bonds (Note 5)	1,583	1,564	1,936	1,928

Level 3 Rollforward

The following table is a reconciliation of changes in fair value of PG&E Corporation's instruments that have been classified as Level 3 in the fair value hierarchy for the twelve month period ended December 31, 2008:

(in millions)	PG&E Corporation						Total
	Money Market Investments	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽³⁾	Long-term Disability	Dividend Participation Rights	Other	
Asset (liability) Balance as of January 1, 2008	\$ -	\$ 115 ⁽¹⁾	\$ 8	\$ 87	\$ (68) ⁽²⁾	\$ (4)	\$ 138
Realized and unrealized gains (losses):							
Included in earnings	-	-	-	(34)	(3)	-	(37)
Included in regulatory assets and liabilities or balancing accounts	-	(271)	(3)	-	-	2	(272)
Purchases, issuances, and settlements	(50)	-	-	25	29	-	4
Transfers in (out) of Level 3	62	-	-	-	-	-	62
Asset (liability) Balance as of December 31, 2008	\$ 12	\$ (156)	\$ 5	\$ 78	\$ (42)	\$ (2)	\$ (105)

⁽¹⁾ Includes the impact of the \$48 million retrospective adjustment related to the CRRs on January 1, 2008. Additionally, the balance includes the impact of netting adjustments of \$6 million made in accordance with the requirements of FIN 39-1.

⁽²⁾ The discount factor used to value these rights was adjusted on January 1, 2008 in order to comply with the provisions of SFAS No. 157, resulting in a \$6 million expense to increase the value of the liability.

⁽³⁾ Excludes taxes on appreciation of investment value.

Earnings for the period were impacted by a \$37 million unrealized loss relating to assets or liabilities still held at December 31, 2008.

The following table is a reconciliation of changes in fair value of the Utility's instruments that have been classified as Level 3 in the fair value hierarchy for the twelve month period ended December 31, 2008:

(in millions)	Utility				
	Price Risk Management Instruments	Nuclear Decommissioning Trusts ⁽²⁾	Long-term Disability	Other	Total
Asset (liability) Balance as of January 1, 2008	\$ 115 ⁽¹⁾	\$ 8	\$ 87	\$ (4)	\$ 206
Realized and unrealized gains (losses):					
Included in earnings	-	-	(34)	-	(34)
Included in regulatory assets and liabilities or balancing accounts	(271)	(3)	-	2	(272)
Purchases, issuances, and settlements	-	-	25	-	25
Transfers in (out) of Level 3	-	-	-	-	-
Asset (liability) Balance as of December 31, 2008	<u>\$ (156)</u>	<u>\$ 5</u>	<u>\$ 78</u>	<u>\$ (2)</u>	<u>\$ (75)</u>

⁽¹⁾ Includes the impact of the \$48 million retrospective adjustment related to the CRRs on January 1, 2008. Additionally, the balance includes the impact of netting adjustments of \$6 million made in accordance with the requirements of FIN 39-1.

⁽²⁾ Excludes taxes on appreciation of investment value.

Earnings for the period were impacted by a \$34 million unrealized loss relating to assets or liabilities still held at December 31, 2008.

PG&E Corporation and the Utility did not have any nonrecurring financial measurements that are within the scope of SFAS No. 157 as of December 31, 2008.

NOTE 13: NUCLEAR DECOMMISSIONING

The Utility's nuclear power facilities consist of two units at Diablo Canyon ("Diablo Canyon Unit 1" and "Diablo Canyon Unit 2") and the retired facility at Humboldt Bay ("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 Nuclear Regulatory Commission ("NRC") license and release of the property for unrestricted use. The Utility makes contributions to trust funds (described below) to provide for the eventual decommissioning of each nuclear unit. The CPUC conducts a Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP") every three years to review the Utility's updated nuclear decommissioning cost study and to determine the level of Utility trust contributions and related revenue requirements. In the Utility's 2005 NDCTP, the CPUC assumed that the eventual decommissioning of Diablo Canyon Unit 1 would be scheduled to begin in 2024 and be completed in 2044; that decommissioning of Diablo Canyon Unit 2 would be scheduled to begin in 2025 and be completed in 2041; and that decommissioning of Humboldt Bay Unit 3 would be scheduled to begin in 2009 and be completed in 2015. A premature shutdown of the Diablo Canyon units would increase the likelihood of an earlier start to decommissioning. The 2008 NDCTP application was originally scheduled to be filed on November 10, 2008; however, on April 29 2008, the CPUC extended the filing date to April 3, 2009.

As presented in the Utility's 2005 NDCTP, the estimated nuclear decommissioning cost for Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately \$2.27 billion in 2008 dollars (or approximately \$5.42 billion in future dollars). These estimates are based on the 2005 decommissioning cost studies, prepared in accordance with CPUC requirements. The Utility's revenue requirements for nuclear decommissioning costs (i.e., the revenue requirements used by the Utility to make contributions to the decommissioning trust funds) are recovered from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear power plants. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates, regulatory requirements, technology, and costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. However, under SFAS No. 143 requirements, the decommissioning cost estimate is calculated using a different method in accordance with SFAS No. 143. Under GAAP, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities and records this as an asset retirement obligation on its Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately \$1.4 billion at December 31, 2008 and \$1.3 billion at December 31, 2007. The primary difference between the Utility's estimated nuclear decommissioning obligation as recorded in accordance with GAAP and the estimate prepared in accordance with the CPUC requirements is that the estimated obligation calculated in accordance with GAAP incorporates various potential settlement dates for the obligation and includes an estimated amount for third-party labor costs in the fair value calculation. Differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the decommissioning obligation recorded in accordance with GAAP are reflected as a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements.)

Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, in order to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. The CPUC has authorized the qualified and non-qualified trusts to invest a maximum of 60% of its funds in publicly-traded equity securities, of which up to 20% may be invested in publicly-traded non-U.S. equity securities. The allocation of the trust funds is monitored monthly. To the extent that market movements cause the asset allocation to move outside these ranges, the investments are rebalanced toward the target allocation.

Trust earnings are included in the nuclear decommissioning trust assets and the corresponding regulatory liability for asset retirement costs. There is no impact on the Utility's earnings. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

During 2008, the trusts earned \$76 million in interest and dividends. All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. All of the Utility's investment securities in the trust are classified as "Available for Sale" in accordance with SFAS No. 115. At December 31, 2008, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately \$1.7 billion, net of deferred taxes on unrealized gains.

In general, investment securities are exposed to various risks, such as interest rate, credit and market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' fair value. (See Note 12 of the Notes to the Consolidated Financial Statements.)

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income. Realized gains and losses are recognized as additions or reductions to trust asset balances. The Utility, however, accounts for its nuclear decommissioning obligations in accordance with SFAS No. 71; therefore, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

At December 31, 2008, total unrealized losses on the investments held in the trusts were \$39 million. SFAS Nos. 115-1 and 124-1 state that an investment is impaired if the fair value of the investment is less than its cost and if the impairment is concluded to be other-than-temporary, an impairment loss is recognized. Since the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to conclude that the \$39 million impairment is not other-than-temporary. As a result, an impairment loss was recognized and the Utility recorded a \$39 million reduction to the nuclear decommissioning trusts assets and the corresponding regulatory liability asset retirement costs.

The following table provides a summary of the fair value of the investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Maturity Date	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Estimated ⁽¹⁾ Fair Value
Year ended December 31, 2008					
U.S. government and agency issues	2009-2038	\$ 617	\$ 103	\$ -	\$ 720
Municipal bonds and other	2009-2049	187	3	(12)	178
Equity securities		588	340	(27)	901
Total		<u>\$ 1,392</u>	<u>\$ 446</u>	<u>\$ (39)</u>	<u>\$ 1,799</u>
Year ended December 31, 2007					
U.S. government and agency issues	2008-2037	\$ 767	\$ 59	\$ -	\$ 826
Municipal bonds and other	2008-2049	209	5	-	214
Equity securities		464	682	(7)	1,139
Total		<u>\$ 1,440</u>	<u>\$ 746</u>	<u>\$ (7)</u>	<u>\$ 2,179</u>

⁽¹⁾ Excludes taxes on appreciation of investment value.

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

(in millions)	Year Ended December 31,		
	2008	2007	2006
Proceeds received from sales of securities	\$ 1,635	\$ 830	\$ 1,087
Gross realized gains on sales of securities held as available-for-sale	30	61	55
Gross realized losses on sales of securities held as available-for-sale	(142)	(42)	(29)

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay. The DOE failed to develop a permanent storage site by January 31, 1998. The Utility believes that the existing spent fuel pools at Diablo Canyon (which include newly constructed temporary storage racks) have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1 and 2011 for Unit 2.

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the NRC to build an on-site dry cask storage facility to store spent fuel through at least 2024. After various parties appealed the NRC's issuance of the permit, the U.S. Court of Appeals for the Ninth Circuit ("Ninth Circuit") issued a decision in 2006 requiring the NRC to issue a supplemental environmental assessment report on the potential environmental consequences in the event of terrorist attack at Diablo Canyon, as well as to review other contentions raised by the appealing parties related to potential terrorism threats. In August 2007, the NRC staff issued a final supplemental environmental assessment report concluding there would be no significant environmental impacts from potential terrorist acts directed at the Diablo Canyon storage facility.

In October 2008, the NRC rejected the final contention that had been made during the appeal. The appellant has filed a petition for review of the NRC's order in the Ninth Circuit. Although the appellant did not seek to obtain an order prohibiting the Utility from loading spent fuel, the petition stated that they may seek a stay of fuel loading at the facility. On December 31, 2008, the appellate court granted the Utility's request to intervene in the proceeding. All briefs by all parties are scheduled to be filed by April 8, 2009.

The construction of the dry cask storage facility is complete and the initial movement of spent nuclear fuel to dry cask storage is expected to begin in June 2009. If the Utility is unable to begin loading spent nuclear fuel by October 2010 for Unit 1 or May 2011 for Unit 2 and if the Utility is otherwise unable to increase its on-site storage capacity, the Utility would have to curtail or halt operations until such time as additional safe storage for spent fuel is made available.

On August 7, 2008, the U.S. Court of Appeals for the Federal Circuit issued an appellate order in the litigation pending against the DOE in which the Utility and other nuclear power plant owners seek to recover costs they incurred to build on-site spent nuclear fuel storage facilities due to the DOE's delay in constructing a national repository for nuclear waste. In October 2006, the U.S. Court of Federal Claims found that the DOE had breached its contract with the Utility but awarded the Utility approximately \$43 million of the \$92 million incurred by the Utility through 2004. In ruling on the Utility's appeal, the U.S. Court of Appeals for the Federal Circuit reversed the lower court on issues relating to the calculation of damages and ordered the lower court to re-calculate the award. Although various motions by the DOE for reconsideration are still pending, the judge in the lower court conducted a status conference on January 15, 2009 and has scheduled another conference for July 9, 2009. The Utility expects the final award will be approximately \$91 million for costs incurred through 2004 and that the Utility will recover all of its costs incurred after 2004 to build on-site storage facilities. Amounts recovered from the DOE will be credited to customers through rates.

PG&E Corporation and the Utility are unable to predict the outcome of any rehearing petition.

NOTE 14: EMPLOYEE COMPENSATION PLANS

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for certain employees and retirees, referred to collectively as pension benefits. PG&E Corporation and the Utility also provide contributory postretirement medical plans for certain employees and retirees and their eligible dependents, and non-contributory postretirement life insurance plans for certain employees and retirees (referred to collectively as "other benefits"). PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Code as qualified trusts. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain Code limitations. The following schedules aggregate all of PG&E Corporation's and the Utility's plans and are presented based on the sponsor of each plan. PG&E Corporation and the Utility use a December 31 measurement date for all plans.

Under SFAS No. 71, regulatory adjustments are recorded in the Consolidated Statements of Income and Consolidated Balance Sheets of the Utility to reflect the difference between pension expense or income for accounting purposes and pension expense or income for ratemaking, which is based on a funding approach. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158 for the pension benefits related to the Utility's qualified benefit pension plan. Since 1993, the CPUC has authorized the Utility to recover the costs associated with its other benefits based on the lesser of the expense under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" ("SFAS No. 106"), or the annual tax deductible contributions to the appropriate trusts. The Utility records a regulatory liability for an overfunded position of other benefits. However, this recovery mechanism does not allow the Utility to record a regulatory asset for an underfunded position related to other benefits. Therefore, the SFAS No. 158 charge is recorded in accumulated other comprehensive income (loss) for other benefits.

Benefit Obligations

The following tables reconcile changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2008 and 2007:

Pension Benefits

	PG&E Corporation		Utility	
	2008	2007	2008	2007
(in millions)				
Projected benefit obligation at January 1	\$ 9,081	\$ 9,064	\$ 9,036	\$ 9,023
Service cost for benefits earned	236	233	234	228
Interest cost	581	544	578	541
Actuarial (gain) loss	258	(397)	255	(396)
Plan amendments	2	1	3	2
Benefits and expenses paid	(391)	(364)	(389)	(362)
Projected benefit obligation at December 31	\$ 9,767	\$ 9,081	\$ 9,717	\$ 9,036
Accumulated benefit obligation	\$ 8,601	\$ 8,243	\$ 8,559	\$ 8,206

Other Benefits

	PG&E Corporation		Utility	
	2008	2007	2008	2007
(in millions)				
Benefit obligation at January 1	\$ 1,311	\$ 1,310	\$ 1,311	\$ 1,310
Service cost for benefits earned	29	29	29	29
Interest cost	81	79	81	79
Actuarial (gain) loss	22	(66)	22	(66)
Plan amendments	-	17	-	17
Gross benefits paid	(101)	(97)	(101)	(97)
Federal subsidy on benefits paid	4	4	4	4
Participants paid benefits	36	35	36	35
Benefit obligation at December 31	<u>\$ 1,382</u>	<u>\$ 1,311</u>	<u>\$ 1,382</u>	<u>\$ 1,311</u>

Change in Plan Assets

To determine the fair value of the plan assets, PG&E Corporation and the Utility use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee.

The following tables reconcile aggregate changes in plan assets during 2008 and 2007:

Pension Benefits

	PG&E Corporation		Utility	
	2008	2007	2008	2007
(in millions)				
Fair value of plan assets at January 1	\$ 9,540	\$ 9,028	\$ 9,540	\$ 9,028
Actual return on plan assets	(1,232)	766	(1,232)	766
Company contributions	182	139	179	137
Benefits and expenses paid	(424)	(393)	(421)	(391)
Fair value of plan assets at December 31	<u>\$ 8,066</u>	<u>\$ 9,540</u>	<u>\$ 8,066</u>	<u>\$ 9,540</u>

Other Benefits

	PG&E Corporation		Utility	
	2008	2007	2008	2007
(in millions)				
Fair value of plan assets at January 1	\$ 1,331	\$ 1,256	\$ 1,331	\$ 1,256
Actual return on plan assets	(316)	107	(316)	107
Company contributions	48	38	48	38
Plan participant contribution	36	36	36	36
Benefits and expenses paid	(109)	(106)	(109)	(106)
Fair value of plan assets at December 31	<u>\$ 990</u>	<u>\$ 1,331</u>	<u>\$ 990</u>	<u>\$ 1,331</u>

Funded Status

The following schedule shows the plans' aggregate funded status on a plan sponsor basis. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2008	2007	2008	2007
(in millions)				
Fair value of plan assets at December 31	\$ 8,066	\$ 9,540	\$ 8,066	\$ 9,540
Projected benefit obligation at December 31	(9,767)	(9,081)	(9,717)	(9,036)
Prepaid/(accrued) benefit cost	\$ (1,701)	\$ 459	\$ (1,651)	\$ 504
Noncurrent asset	\$ -	\$ 532	\$ -	\$ 532
Current liability	(5)	(2)	(3)	(3)
Noncurrent liability	(1,696)	(71)	(1,648)	(25)
Prepaid/(accrued) benefit cost	\$ (1,701)	\$ 459	\$ (1,651)	\$ 504

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2008	2007	2008	2007
(in millions)				
Fair value of plan assets at December 31	\$ 990	\$ 1,331	\$ 990	\$ 1,331
Benefit obligation at December 31	(1,382)	(1,311)	(1,382)	(1,311)
Prepaid/(accrued) benefit cost	\$ (392)	\$ 20	\$ (392)	\$ 20
Noncurrent asset	\$ -	\$ 54	\$ -	\$ 54
Noncurrent liability	(392)	(34)	(392)	(34)
Prepaid/(accrued) benefit cost	\$ (392)	\$ 20	\$ (392)	\$ 20

Other Information

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan asset for plans in which the fair value of plan assets is less than the accumulated benefit obligation and the projected benefit obligation as of December 31, 2008 and 2007 were as follows:

	Pension Benefits		Other Benefits	
	2008	2007	2008	2007
(in millions)				
PG&E Corporation:				
Projected benefit obligation	\$ (9,767)	\$ (73)	\$ (1,382)	\$ (187)
Accumulated benefit obligation	(8,601)	(64)	-	-
Fair value of plan assets	8,066	-	990	153
Utility:				
Projected benefit obligation	\$ (9,717)	\$ (27)	\$ (1,382)	\$ (187)
Accumulated benefit obligation	(8,559)	(27)	-	-
Fair value of plan assets	8,066	-	990	153

Components of Net Periodic Benefit Cost

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2008, 2007, and 2006, is as follows:

Pension Benefits

	December 31,		
	2008	2007	2006
(in millions)			
Service cost for benefits earned	\$ 236	\$ 233	\$ 236
Interest cost	581	544	511
Expected return on plan assets	(696)	(711)	(640)
Amortization of prior service cost ⁽¹⁾	47	49	56
Amortization of unrecognized gain ⁽¹⁾	1	2	22
Net periodic benefit cost	\$ 169	\$ 117	\$ 185

⁽¹⁾ In 2007 and 2008, under SFAS No.158, PG&E Corporation and the Utility recorded amounts related to pension and other benefits in other comprehensive income, net of related deferred taxes, except for a portion recorded as a regulatory liability in accordance with SFAS No. 71.

Other Benefits

	December 31,		
	2008	2007	2006
(in millions)			
Service cost for benefits earned	\$ 29	\$ 29	\$ 28
Interest cost	81	79	74
Expected return on plan assets	(93)	(96)	(90)
Amortization of transition obligation ⁽¹⁾	26	26	26
Amortization of prior service cost ⁽¹⁾	16	16	14
Amortization of unrecognized gain ⁽¹⁾	(15)	(10)	(3)
Net periodic benefit cost	\$ 44	\$ 44	\$ 49

⁽¹⁾ In 2007 and 2008, under SFAS No.158, PG&E Corporation and the Utility recorded amounts related to pension and other benefits in other comprehensive income, net of related deferred taxes, except for a portion recorded as a regulatory liability in accordance with SFAS No. 71.

There was no material difference between PG&E Corporation and the Utility's consolidated net periodic benefit costs.

Components of Accumulated Other Comprehensive Income

Since December 31, 2006, the effective date of SFAS No. 158, PG&E Corporation and the Utility have recorded unrecognized prior service costs, unrecognized gains and losses, and unrecognized net transition obligations as components of accumulated other comprehensive income, net of tax. In subsequent years, PG&E Corporation and the Utility recognize these amounts as components of net periodic benefit cost in accordance with SFAS No. 87, "Employers' Accounting for Pensions," and SFAS No. 106.

Pre-tax amounts recognized in accumulated other comprehensive income consist of:

	PG&E Corporation		Utility	
	2008	2007	2008	2007
(in millions)				
Pension Benefits:				
Beginning unrecognized prior service cost	\$ (222)	\$ (268)	\$ (226)	\$ (275)
Current year unrecognized prior service cost	(2)	(3)	(3)	(2)
Amortization of unrecognized prior service cost	49	49	48	51
Unrecognized prior service cost	(175)	(222)	(181)	(226)
Beginning unrecognized net gain (loss)	105	(318)	117	(306)
Current year unrecognized net gain (loss)	(2,219)	421	(2,217)	423
Amortization of unrecognized net gain	1	2	-	-
Unrecognized net gain (loss)	(2,113)	105	(2,100)	117
Beginning unrecognized net transition obligation	-	(1)	-	(1)
Amortization of unrecognized net transition obligation	-	1	-	1
Unrecognized net transition obligation	-	-	-	-
Less: transfer to regulatory account ⁽¹⁾	2,259	109	2,259	109
Total	\$ (29)	\$ (8)	\$ (22)	\$ -
Other Benefits:				
Beginning unrecognized prior service cost	\$ (116)	\$ (114)	\$ (116)	\$ (114)
Current year unrecognized prior service cost	-	(18)	-	(18)
Amortization of unrecognized prior service cost	17	16	17	16
Unrecognized prior service cost	(99)	(116)	(99)	(116)
Beginning unrecognized net gain	311	250	311	250
Current year unrecognized net gain (loss)	(438)	71	(438)	71
Amortization of unrecognized net loss	(15)	(10)	(15)	(10)
Unrecognized net gain (loss)	(142)	311	(142)	311
Beginning unrecognized net transition obligation	(128)	(154)	(128)	(154)
Amortization of unrecognized net transition obligation	26	26	26	26
Unrecognized net transition obligation	(102)	(128)	(102)	(128)
Less: transfer to regulatory account ⁽²⁾	-	(44)	-	(44)
Total	\$ (343)	\$ 23	\$ (343)	\$ 23

⁽¹⁾ The Utility recorded approximately \$2,259 million in 2008 and \$109 million in 2007 as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71. The adjustment resulted in a regulatory asset balance at December 31, 2008.

⁽²⁾ The Utility recorded approximately \$44 million in 2007 as an addition to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71.

The estimated amounts that will be amortized into net periodic benefit cost in 2009 are as follows:

	PG&E Corporation	Utility
(in millions)		
Pension benefits :		
Unrecognized prior service cost	\$ 47	\$ 48
Unrecognized net loss	98	97
Total	\$ 145	\$ 145
Other benefits:		
Unrecognized prior service cost	\$ 16	\$ 16
Unrecognized net loss	3	3
Unrecognized net transition obligation	26	26
Total	\$ 45	\$ 45

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. Weighted average year-end assumptions were used in determining the plans' projected benefit obligations, while prior year-end assumptions are used to compute net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2008	2007	2006	2008	2007	2006
Discount rate	6.31%	6.31%	5.90%	5.85-6.33%	5.52-6.42%	5.50-6.00%
Average rate of future compensation increases	5.00%	5.00%	5.00%	-	-	-
Expected return on plan assets	7.30%	7.40%	8.00%	7.00-7.30%	7.00-7.50%	7.30-8.20%

The assumed health care cost trend rate for 2008 is approximately 8%, decreasing gradually to an ultimate trend rate in 2014 and beyond of approximately 5%. A one-percentage point change in assumed health care cost trend rate would have the following effects:

(in millions)	One- Percentage Point Increase	One- Percentage Point Decrease
Effect on postretirement benefit obligation	\$ 68	\$ (57)
Effect on service and interest cost	7	(6)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income returns were projected based on real maturity and credit spreads added to a long-term inflation rate. Equity returns were estimated based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility pension plan, the assumed return of 7.3% compares to a ten-year actual return of 4.6%. The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from market data of over approximately 300 Aa-grade non-callable bonds at December 31, 2008. This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The difference between actual and expected return on plan assets is included in unrecognized gain (loss), and is considered in the determination of future net periodic benefit income (cost). The actual return on plan assets was above the expected return in 2007 and 2006. The actual return on plan assets for 2008 was lower than the expected return due to the significant decline in equity market values that occurred in 2008.

Asset Allocations

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2008 and 2007, and target 2009 allocation, were as follows:

	Pension Benefits			Other Benefits		
	2009	2008	2007	2009	2008	2007
Equity securities						
U.S. equity	32%	31%	30%	37%	35%	36%
Non-U.S. equity	18%	17%	18%	18%	16%	19%
Global equity	5%	3%	5%	3%	2%	4%
Absolute return	5%	4%	5%	3%	3%	3%
Fixed income securities	40%	42%	41%	34%	34%	37%
Cash	0%	3%	1%	5%	10%	1%
Total	100%	100%	100%	100%	100%	100%

Equity securities include a small amount (less than 0.1% of total plan assets) of PG&E Corporation common stock.

During 2008, the duration of fixed income assets was extended to better align with the interest rate sensitivity of the benefit plan liability. The maturity of fixed income securities at December 31, 2008 ranged from zero to 59 years and the average duration of the bond portfolio was approximately 12.2 years. The maturity of fixed income securities at December 31, 2007 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 10.5 years.

PG&E Corporation's investment strategy for all plans is to maintain actual asset weightings within 1.0% to 5.0% of target asset allocations varying by asset class. A rebalancing review is triggered whenever the actual weighting falls outside of the specified range.

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of fixed income securities. Investment managers for each asset class are retained to either passively or actively manage the combined portfolio against the benchmark. Active management covers approximately 70% of the U.S. equity, 80% of the non-U.S. equity, and virtually 100% of the fixed income and global security portfolios.

During 2007, PG&E Corporation began extending the benchmarks of its fixed income managers and began using interest rate swaps for certain plans in order to better match the interest rate sensitivity of the plans' assets with that of the plans' liabilities. Changes in the value of these investments will affect future contributions to the trust and net periodic benefit cost on a lagged basis.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility contributed approximately \$182 million to the pension benefits, including \$176 million to the qualified defined benefit pension plan, and approximately \$48 million to the other benefit plans in 2008. These contributions are consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory decisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2008. The Utility's pension benefits met all the funding requirements under the Employee Retirement Income Security Act of 1974, as amended. PG&E Corporation and the Utility expect to make total contributions of approximately \$176 million annually during 2009 and 2010 to the pension plan and expect to make contributions of approximately \$58 million annually for the years 2009 and 2010 to other postretirement benefit plans.

Benefits Payments

The estimated benefits expected to be paid in each of the next five fiscal years and in aggregate for the five fiscal years thereafter, are as follows:

	PG&E Corporation		Utility	
(in millions)				
Pension				
2009	\$	440	\$	437
2010		470		467
2011		502		500
2012		538		536
2013		575		573
2014-2018		3,433		3,415
Other benefits				
2009	\$	98	\$	98
2010		101		101
2011		104		104
2012		105		105
2013		108		108
2014-2018		572		572

Defined Contribution Benefit Plans

PG&E Corporation and its subsidiaries also sponsor defined contribution benefit plans. These plans are qualified under applicable sections of the Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Before April 1, 2007, PG&E Corporation employees received matching of up to 5% of the employee's base compensation and basic contributions of up to 5% of the employee's base compensation. Matching contributions vary up to 6% of the employee's base compensation based on years of service for Utility employees. Beginning April 1, 2007, the basic employer contribution was discontinued for PG&E Corporation employees and matching contributions were changed to match the Utility employee plan. Matching employer contributions are made with company stock, however, employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time after they have been credited to the employee's account. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Income amounted to:

(in millions)	PG&E Corporation	Utility
Year ended December 31,		
2008	\$ 53	\$ 52
2007	47	46
2006	45	43

PG&E Corporation Supplemental Retirement Savings Plan

The PG&E Corporation Supplemental Retirement Savings Plan (“SRSP”) is a non-qualified plan that allows eligible officers and key employees of PG&E Corporation and its subsidiaries to defer 5% to 50% of their base salary and all or part of their incentive awards. In addition, to the extent that matching employer contributions cannot be made to a participant under the qualified defined contribution benefit plan because the contributions would exceed the limitations set by the Code, PG&E Corporation credits the excess amount to an SRSP account for the eligible employee. Each SRSP participant has a separate account which is adjusted on a monthly basis to reflect the performance of the investment options selected by the participant. The change in the value of participants’ accounts is recorded as additional compensation expense or income in the Consolidated Statements of Income. Total compensation expense and (income) recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

(in millions)	PG&E Corporation	Utility
2008	\$ (7)	\$ (4)
2007	2	1
2006	4	2

Long-Term Incentive Plan

The 2006 LTIP permits the award of various forms of incentive awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, deferred compensation awards, and other stock-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive restricted stock and either stock options or restricted stock units under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for issuance under the 2006 LTIP, of which 10,342,381 shares were available for award at December 31, 2008.

Awards made under the PG&E Corporation Long-Term Incentive Program before December 31, 2005 and still outstanding continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program.

PG&E Corporation and the Utility use an estimated annual forfeiture rate of 2.5% for stock options and restricted stock and 3% for performance shares, based on historic forfeiture rates, for purposes of determining compensation expense for share-based incentive awards. The following table provides a summary of total compensation expense for PG&E Corporation and the Utility for share-based incentive awards for the years ended December 31, 2007 and 2008:

	Year ended December 31, 2008	
(in millions)	PG&E Corporation	Utility
Stock Options	\$ 2	\$ 2
Restricted Stock	22	15
Performance Shares	33	20
Total Compensation Expense (pre-tax)	\$ 57	\$ 37
Total Compensation Expense (after-tax)	\$ 34	\$ 22

	Year ended December 31, 2007	
(in millions)	PG&E Corporation	Utility
Stock Options	\$ 7	\$ 4
Restricted Stock	24	15
Performance Shares	(8)	(7)
Total Compensation Expense (pre-tax)	\$ 23	\$ 12
Total Compensation Expense (after-tax)	\$ 14	\$ 7

Stock Options

Other than the grant of options to purchase 4,032 shares of PG&E Corporation common stock to non-employee directors of PG&E Corporation in accordance with the formula and nondiscretionary provisions of the 2006 LTIP, no other stock options were granted during 2008. The exercise price of stock options granted under the 2006 LTIP and all other outstanding stock options is equal to the market price of PG&E Corporation's common stock on the date of grant. Stock options generally have a ten-year term and vest over four years of continuous service, subject to accelerated vesting in certain circumstances.

The fair value of each stock option on the date of grant is estimated using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was \$4.46, \$7.81, and \$6.98 per share in 2008, 2007, and 2006, respectively. The significant assumptions used for shares granted in 2008, 2007, and 2006 were:

	2008	2007	2006
Expected stock price volatility	18.9%	16.5%	22.1%
Expected annual dividend payment	\$ 1.56	\$ 1.44	\$ 1.32
Risk-free interest rate	2.77%	4.73%	4.46%
Expected life	5.4 years	5.4 years	5.6 years

Expected volatilities are based on historical volatility of PG&E Corporation's common stock. The expected dividend payment is the dividend yield at the date of grant. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant. The expected life of stock options is derived from historical data that estimates stock option exercises and employee departure behavior.

The following table summarizes total intrinsic value (fair market value of PG&E Corporation's stock less stock option strike price) of options exercised for PG&E Corporation and the Utility in 2008, 2007, and 2006:

	PG&E Corporation	Utility
(in millions)		
2008:		
Intrinsic value of options exercised	\$ 13	\$ 9
2007:		
Intrinsic value of options exercised	\$ 59	\$ 34
2006:		
Intrinsic value of options exercised	\$ 97	\$ 51

The tax benefit from stock options exercised totaled \$4 and \$20 million for the year ended December 31, 2008 and December 31, 2007, respectively, of which approximately \$3 million and \$10 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2008:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	3,882,672	\$ 24.00		
Granted ⁽¹⁾	4,032	\$ 37.91		
Exercised	(900,732)	\$ 25.72		
Forfeited or expired	(17,711)	\$ 31.49		
Outstanding at December 31	2,968,261	\$ 23.45	3.75	\$ 45,300,037
Expected to vest at December 31	254,854	\$ 33.74	6.00	\$ 1,270,206
Exercisable at December 31	2,712,725	\$ 22.48	3.54	\$ 44,029,831

⁽¹⁾ No stock options were awarded to employees in 2008; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for 2008:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1 ⁽¹⁾	2,912,552	\$ 23.40		
Granted	-	-		
Exercised	(588,333)	\$ 24.86		
Forfeited or expired	(14,396)	\$ 31.14		
Outstanding at December 31 ⁽¹⁾	<u>2,309,823</u>	\$ 22.99	3.79	\$ 36,318,945
Expected to vest at December 31	<u>164,303</u>	\$ 33.09	5.80	\$ 923,072
Exercisable at December 31	<u>2,145,520</u>	\$ 22.21	3.64	\$ 35,395,873

⁽¹⁾ Includes net employee transfers between PG&E Corporation and the Utility during 2008.

As of December 31, 2008, there was less than \$1 million of total unrecognized compensation cost related to outstanding stock options. That cost is expected to be recognized over a weighted average period of less than one year for PG&E Corporation and the Utility.

Restricted Stock

During 2008, PG&E Corporation awarded 591,294 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 396,854 shares were awarded to the Utility's eligible participants.

Although the recipients of restricted stock can vote their shares, they may not sell or transfer their shares until the shares vest. For restricted stock awarded in 2005, there were no performance criteria and the restrictions lapsed ratably over four years. The terms of the restricted stock awarded in 2006, 2007, and 2008, provide that 60% of the shares will vest over a period of three years at the rate of 20% per year. If PG&E Corporation's annual total shareholder return ("TSR") is in the top quartile of its comparator group, as measured for the three immediately preceding calendar years, the restrictions on the remaining 40% of the shares will lapse in the third year. If PG&E Corporation's TSR is not in the top quartile for such period, then the restrictions on the remaining 40% of the shares will lapse in the fifth year. Compensation expense related to the portion of the restricted stock award that is subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years. Dividends declared on restricted stock are paid to recipients only when the restricted stock vests.

The tax benefit from restricted stock which vested during 2008 and 2007 totaled \$2 and \$7 million, respectively, of which approximately \$1 million and \$5 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2008:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,261,125	\$ 40.51
Granted	591,294	\$ 37.91
Vested	(440,652)	\$ 37.20
Forfeited	(124,198)	\$ 43.27
Nonvested at December 31	<u>1,287,569</u>	\$ 40.18

The following table summarizes restricted stock activity for the Utility for 2008:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1 ⁽¹⁾	859,745	\$ 40.65
Granted	396,854	\$ 37.91
Vested	(303,923)	\$ 37.46
Forfeited	(95,746)	\$ 43.12
Nonvested at December 31	<u>856,930</u>	<u>\$ 40.24</u>

⁽¹⁾ Includes net employee transfers between PG&E Corporation and the Utility during 2008.

As of December 31, 2008, there was approximately \$20 million of total unrecognized compensation cost relating to restricted stock, of which \$15 million related to the Utility. The cost is expected to be recognized over a weighted average period of 1.2 years by PG&E Corporation and the Utility.

Performance Shares

During 2008, PG&E Corporation awarded 581,175 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 396,230 shares were awarded to the Utility's eligible participants. Performance shares are hypothetical shares of PG&E Corporation common stock that vest at the end of a three-year performance period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive, if any, is determined by multiplying the number of vested performance shares by the average closing price of PG&E Corporation common stock for the last 30 calendar days of the last year in the three year performance period. This result is then adjusted by a payout percentage ranging from 0% to 200% as measured by PG&E Corporation's TSR relative to its comparator group for the applicable three-year performance period. During 2008, PG&E Corporation paid \$6.9 million to performance share recipients, of which \$5 million related to Utility employees.

As of December 31, 2008, \$46 million was accrued as the performance share liability for PG&E Corporation, of which \$29.7 million related to Utility employees. The number of performance shares that were outstanding at December 31, 2008 was 1,422,302, of which 938,059 was related to Utility employees. Outstanding performance shares are classified as a liability on the Consolidated Balance Sheets of PG&E Corporation and the Utility because the performance shares can only be settled in cash. The liability related to the performance shares is marked to market at the end of each reporting period to reflect the market price of PG&E Corporation common stock and the payout percentage at the end of the reporting period. Accordingly, compensation expense recognized for performance shares will fluctuate with PG&E Corporation's common stock price and its TSR relative to its comparator group.

NOTE 15: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding under Chapter 11 seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers, are seeking refunds from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets between May 2000 and June 2001.

While the FERC and judicial proceedings have been pending, the Utility entered into a number of settlements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. The proceeds from these settlements, after deductions for contingencies based on the outcome of the various refund offset and interest issues being considered by the FERC, will continue to be refunded to customers in rates. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from energy suppliers through resolution of the remaining disputed claims, either through settlement or the conclusion of the various FERC and judicial proceedings, will also be credited to customers.

The following table presents the changes in the remaining disputed claims liability and interest accrued from December 31, 2007:

(in millions)	
Balance at December 31, 2007	\$ 1,719
Interest accrued	80
Less: Settlements	(49)
Balance at December 31, 2008	<u>\$ 1,750</u>

As of December 31, 2008, the Utility's net disputed claims liability was approximately \$1,750 million, consisting of approximately \$1,580 million of remaining disputed claims (classified on the Consolidated Balance Sheets as Accounts payable – Disputed claims and customer refunds) and interest accrued at the FERC-ordered rate of \$664 million (classified on the Consolidated Balance Sheets as Interest payable) offset by accounts receivable from the CAISO and PX of approximately \$494 million (classified on the Consolidated Balance Sheets as Accounts receivable – Customers).

In connection with the Utility's proceedings under Chapter 11, the Utility established an escrow account for the payment of the disputed claims, which is classified on the Consolidated Balance Sheets as Restricted cash. As of December 31, 2008, the Utility held \$1,212 million in escrow, including interest earned, for payment of the remaining net disputed claims.

Interest accrues on the liability for disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers, this amount is not held in escrow. If the amount of interest accrued at the FERC-ordered rate is greater than the amount of interest ultimately determined to be owed with respect to disputed claims, the Utility would refund to customers any excess net interest collected from customers. The amount of any interest that the Utility may be required to pay will depend on the final amounts to be paid by the Utility with respect to the disputed claims.

The Utility and the PX have been negotiating the terms of a proposed agreement regarding the potential transfer of \$700 million to the PX from the Utility's escrow account established for disputed claims to enable the PX to fund future settlements, pay refund claims, or amounts owed to CAISO or PX markets, as may be authorized by the FERC or a court of competent jurisdiction. The proposed agreement would be subject to approval by the FERC and by the bankruptcy courts that have jurisdiction of the Chapter 11 proceedings of the PX and the Utility. Under the proposed agreement, the Utility's payment would reduce its liability for remaining net disputed claims. To protect the Utility against the imposition of double liability, the proposed agreement would provide that, to the extent that both the PX and an individual electricity supplier have filed claims relating to the same transaction, such claim would be paid by the Utility only once, either to the PX or directly to the electricity supplier, as may be ordered by the FERC or a court of competent jurisdiction. It is uncertain when a final agreement will be executed and, if executed, when required approvals would be obtained.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings will be resolved, and the amount of any potential refunds that the Utility may receive or the amount of disputed claims, including interest, the Utility will be required to pay.

NOTE 16: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed upon allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and accounting requirements of its regulatory agencies.

The Utility's significant related party transactions were as follows:

	Year Ended December 31,		
	2008	2007	2006
(in millions)			
Utility revenues from:			
Administrative services provided to PG&E Corporation	\$ 4	\$ 4	\$ 5
Interest from PG&E Corporation on employee benefit assets	-	1	1
Utility expenses from:			
Administrative services received from PG&E Corporation	\$ 122	\$ 107	\$ 108
Utility employee benefit payments provided to PG&E Corporation	2	4	3

At December 31, 2008 and December 31, 2007, the Utility had a receivable of approximately \$29 million from PG&E Corporation included in Accounts receivable – Related parties and Other Noncurrent Assets – Related parties receivable on the Utility's Consolidated Balance Sheets and a payable of approximately \$25 million and \$28 million, respectively to PG&E Corporation included in Accounts payable – Related parties on the Utility's Consolidated Balance Sheets.

NOTE 17: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, regulatory proceedings, nuclear operations, employee matters, environmental compliance and remediation, tax matters, and legal matters.

Commitments

Utility

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase electric energy and capacity and makes payments under existing power purchase agreements. The price of purchased power may be fixed or variable. Variable pricing is generally based on either the current market price of gas or electricity at the date of purchase.

Qualifying Facility Power Purchase Agreements – Under the Public Utility Regulatory Policies Act of 1978 (“PURPA”), electric utilities were required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities (“QFs”). To implement the purchase requirements of PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with QFs and approved the applicable terms, conditions, prices, and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the QF’s actual electrical output and CPUC-approved energy prices, while capacity payments are based on the QF’s total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF exceeds or fails to meet performance requirements specified in the applicable power purchase agreement.

The Energy Policy Act of 2005 significantly amended the purchase requirements of PURPA. As amended, Section 210(m) of PURPA authorizes the FERC to waive the obligation of an electric utility under Section 210 of PURPA to purchase the electricity offered to it by a QF (under a new contract or obligation) if the FERC finds the QF has nondiscriminatory access to one of three defined categories of competitive wholesale electricity markets. The statute permits such waivers to a particular QF or on a “service territory-wide basis.” The Utility plans to wait until after the new day-ahead market structure provided for in the CAISO’s MRTU initiative to restructure the California electricity market becomes effective to assess whether it will file a request with the FERC to terminate its obligations under PURPA and to enter into new QF purchase obligations.

As of December 31, 2008, the Utility had agreements with 246 QFs for approximately 3,900 MW that are in operation. Agreements for approximately 3,600 MW expire at various dates between 2009 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. The Utility also has power purchase agreements with 74 inoperative QFs. The total of approximately 3,900 MW consists of approximately 2,500 MW from cogeneration projects, 600 MW from wind projects and 800 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar, and hydroelectric. QF power purchase agreements accounted for approximately 18%, 20%, and 20% of the Utility’s 2008, 2007, and 2006 electricity sources, respectively. No single QF accounted for more than 5% of the Utility’s 2008, 2007, or 2006 electricity sources.

Irrigation Districts and Water Agencies – The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts’ and water agencies’ debt service requirements, whether or not any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2010 to 2031. The Utility’s irrigation district and water agency contracts accounted for approximately 2%, 3%, and 6% of the Utility’s electricity sources in 2008, 2007, and 2006, respectively.

Renewable Energy Contracts – California law requires that each California retail seller of electricity, except for municipal utilities, increase its purchases of renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity delivered from renewable resources equals at least 20% of its total retail sales by the end of 2010. The Utility has entered into new renewable power purchase contracts that will help the Utility meet this renewable portfolio standard (“RPS”) by 2010.

Long-Term Power Purchase Agreements – In accordance with the Utility’s CPUC-approved long-term procurement plans, the Utility has entered into several power purchase agreements with third parties. The Utility’s obligations under a portion of these agreements are contingent on the third party’s development of a new generation facility to provide the power to be purchased by the Utility under the agreements.

Annual Receipts and Payments – The payments made under QFs, irrigation district and water agency, renewable energy, and other power purchase agreements during 2008, 2007 and 2006 were as follows:

(in millions)	2008	2007	2006
Qualifying facility energy payments	\$ 969	\$ 812	\$ 661
Qualifying facility capacity payments	343	363	366
Irrigation district and water agency payments	69	72	64
Renewable energy and capacity payments	714	604	429
Other power purchase agreement payments	2,036	1,166	670

The amounts above do not include payments related to DWR purchases for the benefit of the Utility’s customers, as the Utility only acts as an agent for the DWR.

At December 31, 2008, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	Qualifying Facility		Irrigation District & Water Agency		Renewable		Other		Total Payments
	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Energy	Capacity	
2009	\$ 949	\$ 412	\$ 38	\$ 26	\$ 427	\$ 12	\$ 5	\$ 270	\$ 2,139
2010	960	378	45	23	460	7	6	281	2,160
2011	947	364	46	21	602	7	7	164	2,158
2012	808	334	32	21	688	7	7	86	1,983
2013	755	324	21	15	583	-	7	71	1,776
Thereafter	4,882	1,866	46	38	6,986	-	3	1,038	14,859
Total	\$ 9,301	\$ 3,678	\$ 228	\$ 144	\$ 9,746	\$ 33	\$ 35	\$ 1,910	\$ 25,075

The following table shows the future fixed capacity payments due under the QF contracts that are accounted for as capital leases. These amounts are also included in the table above. The fixed capacity payments are discounted to the present value shown in the table below using the Utility's incremental borrowing rate at the inception of the leases.

The amount of this discount is shown in the table below as the amount representing interest:

(in millions)	
2009	\$ 50
2010	50
2011	50
2012	50
2013	50
Thereafter	204
Total fixed capacity payments	454
Amount representing interest	110
Present value of fixed capacity payments	\$ 344

Minimum lease payments associated with the lease obligation are included in Cost of electricity on PG&E Corporation and the Utility's Consolidated Statements of Income. In accordance with SFAS No. 71, the timing of the Utility's recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are accounted for as capital leases expire between April 2014 and September 2021.

At December 31, 2008, the Utility had approximately \$30 million included in Current Liabilities – Other and \$314 million included in Noncurrent Liabilities – Other representing the present value of the fixed capacity payments due under these contracts recorded on the Utility's Consolidated Balance Sheets. The corresponding assets of \$344 million, including amortization of \$64 million, are included in Property, Plant, and Equipment on the Utility's Consolidated Balance Sheets at December 31, 2008.

Capacity payments, which allow QFs to recover investment costs, are based on the QF's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the QF exceeds or fails to meet performance requirements specified in the applicable power purchase agreement.

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts have fluctuated generally based on market conditions. At December 31, 2008, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2009	\$ 898
2010	183
2011	115
2012	49
2013	42
Thereafter	157
Total	\$ 1,444

Payments for natural gas purchases and gas transportation services amounted to approximately \$2.7 billion in 2008, \$2.2 billion in 2007, and \$2.2 billion in 2006.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from 1 to 16 years and are intended to ensure long-term fuel supply. The contracts for uranium, conversion and enrichment services provide for 100% coverage of reactor requirements through 2010, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2011. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from market-based prices to base prices that are escalated using published indices. New agreements are primarily based on forward market pricing and will begin to impact nuclear fuel costs starting in 2010.

At December 31, 2008, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2009	\$ 95
2010	108
2011	92
2012	79
2013	81
Thereafter	495
Total	<u>\$ 950</u>

Payments for nuclear fuel amounted to approximately \$157 million in 2008, \$102 million in 2007, and \$106 million in 2006.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, vehicle leasing, and telecommunication and information system contracts. At December 31, 2008, the future minimum payments related to other commitments were as follows:

(in millions)	
2009	\$ 45
2010	18
2011	17
2012	17
2013	16
Thereafter	34
Total	<u>\$ 147</u>

Payments for other commitments and operating leases amounted to approximately \$41 million in 2008, \$38 million in 2007, and \$100 million in 2006.

Underground Electric Facilities

At December 31, 2008, the Utility was committed to spending approximately \$228 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities, counties, and telephone utilities involved. The Utility expects to spend approximately \$40 million to \$60 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain indemnity obligations of its former subsidiary, NEGT, that were issued to the purchaser of an NEGT subsidiary company. PG&E Corporation's sole remaining exposure relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser, and is limited to \$150 million. PG&E Corporation has not received any claims nor does it consider it probable that any claims will be made under the guarantee. PG&E Corporation believes its potential exposure under this guarantee would not have a material impact on its financial condition or results of operations.

Utility

Application to Recover Hydroelectric Facility Divestiture Costs

On April 14, 2008, the Utility filed an application with the CPUC requesting authorization to recover approximately \$47 million, including \$12.2 million of interest, of the costs it incurred in connection with the Utility's efforts to determine the market value of its hydroelectric generation facilities in 2000 and 2001. These efforts were undertaken at the direction of the CPUC in preparation for the proposed divestiture of the facilities to further the development of a competitive generation market in California. The Utility continues to own its hydroelectric generation assets. On February 18, 2009, a proposed decision was issued by the administrative law judge, which if adopted by the CPUC, would allow the Utility to recover these costs. It is expected that the CPUC will issue a final decision in 2009.

Electricity purchased under the DWR allocated power purchase contracts with various generators provided approximately 15.1% of the electricity delivered to the Utility's customers for the year ended December 31, 2008. The DWR remains legally and financially responsible for its power purchase contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

The DWR has stated publicly in the past that it intends to transfer full legal title of, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. In addition, the Chapter 11 Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's will be no less than A2 and the Utility's long-term issuer credit rating by S&P will be no less than A. The Utility's current issuer rating by Moody's is A3 and the Utility's long-term issuer credit rating by S&P is BBB+;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

In February 2008, the CPUC, opened an investigation of how the DWR can end its role in purchasing power for the customers of the California investor-owned utilities through novation of the DWR contracts or otherwise. In November 2008, the CPUC issued a decision directing the investor owned utilities to proceed with efforts to novate or renegotiate the DWR contracts, and set a tentative goal of January 1, 2010 for completing novation or renegotiations. However, the CPUC recognized that various uncertainties may influence the achievement of this goal, and indicated that it will continue to monitor the progress of the investor-owned utilities, and make mid-course adjustments as necessary. Until the DWR's obligation under its power purchase contracts are terminated, the CPUC is prohibited by state law from reinstating "direct access." Direct access is the ability of retail end-user customers to purchase electricity from energy providers other than the California investor-owned electric utilities.

Incentive Ratemaking for Energy Efficiency Programs

The CPUC has established an incentive ratemaking mechanism applicable to the California investor-owned utilities' implementation of their energy efficiency programs funded for the 2006-2008 and 2009-2011 program cycles. The maximum amount of revenue that the Utility could earn, and the maximum amount that the Utility could be required to reimburse customers, over the 2006-2008 program cycle is \$180 million.

On December 18, 2008, the CPUC awarded the Utility \$41.5 million in interim shareholder incentive revenues for the 2006-2007 interim claim, ruling that 65% of the 2006-2007 incentive claims should be "held back" until completion of final measurement studies and a final verification report for the entire three-year program cycle.

As long as the final measured energy savings are at least 65% of each of the CPUC's individual savings goals over the 2006-2008 program period, the utilities will not be required to pay back any incentives received on an interim basis. The CPUC also ruled that the utilities will not be entitled to any additional incentives for the 2006-2008 program period beyond the incentives already received if the utility's performance falls within a "deadband;" i.e., if a utility achieves (1) less than 80% of the CPUC's goal for any individual savings metric or (2) less than 85% of the CPUC's overall energy savings goal but greater than 65% of the CPUC's goal for each individual savings metric. On February 2, 2009, The Utility Reform Network and the CPUC's Division of Ratepayer Advocates filed an application for rehearing of the CPUC's December 18, 2008 award.

On January 29, 2009 the CPUC instituted a new proceeding to modify the existing incentive ratemaking mechanism, to adopt a new framework to review the utilities' 2008 energy efficiency performance, and to conduct a final review of the utilities' performance over the 2006-2008 program period. The CPUC also plans to develop a long-term incentive mechanism for program periods beginning in 2009 and beyond.

Whether the Utility will receive all or a portion of the remaining \$77 million in incentives for the 2006 and 2007 program years, whether the Utility will receive any additional incentives or incur a reimbursement obligation in 2009 based on the second interim claim, and whether the final true-up in 2010 will result in a positive or negative adjustment, depends on the new framework and rules to be adopted by the CPUC.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear operating units at its Diablo Canyon nuclear generating facilities and for its retired nuclear generation facility at Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited ("NEIL"). NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.24 billion per incident for Diablo Canyon. In addition, NEIL provides \$131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to \$39.3 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. Under the Terrorism Risk Insurance Program Reauthorization Act of 2007 ("TRIPRA"), acts of terrorism may be "certified" by the Secretary of the Treasury. For a certified act of terrorism, NEIL can obtain compensation from the federal government and will provide up to the full policy limits to the Utility for an insured loss. If one or more non-certified acts of terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member, the maximum recovery under all those nuclear insurance policies may not exceed \$3.24 billion within a 12-month period plus the additional amounts recovered by NEIL for these losses from reinsurance. (TRIPRA extends the Terrorism Risk Insurance Act of 2002 through December 31, 2014.)

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to \$12.5 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$300 million for Diablo Canyon. The balance of the \$12.5 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of \$300 million, then the Utility may be responsible for up to \$117.5 million per reactor, with payments in each year limited to a maximum of \$17.5 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors, each with a rated capacity of over 100 MW, the Utility may be assessed up to \$235 million per incident, with payments in each year limited to a maximum of \$35 million per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

In addition, the Utility has \$53.3 million of liability insurance for Humboldt Bay Unit 3 and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the \$53.3 million of liability insurance.

Environmental Matters

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under environmental laws. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances at former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of possible clean-up costs. The Utility reviews its remediation liability on a quarterly basis. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure using current technology, and considering enacted laws and regulations, experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. The Utility estimates the upper end of this cost range using possible outcomes that are least favorable to the Utility. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

The Utility had an undiscounted and gross environmental remediation liability of approximately \$568 million at December 31, 2008, and approximately \$528 million at December 31, 2007. The \$568 million accrued at December 31, 2008 consists of:

- Approximately \$51 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- Approximately \$167 million for remediation at the Utility's natural gas compressor site located in Topock, Arizona near the California border;
- Approximately \$83 million related to remediation at divested generation facilities;
- Approximately \$216 million related to remediation costs for the Utility's generation and other facilities, third-party disposal sites, and manufactured gas plant sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites); and
- Approximately \$51 million related to remediation costs for fossil decommissioning sites.

Of the approximately \$568 million environmental remediation liability, approximately \$123 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately \$356 million will be recoverable in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers. Environmental remediation associated with the Hinkley natural gas compressor site is not recoverable from customers.

The Utility's undiscounted future costs could increase to as much as \$944 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated, and could increase further if the Utility chooses to remediate beyond regulatory requirements. The amount of approximately \$944 million does not include any estimate for any potential costs of remediation at former manufactured gas plant sites owned by others, unless the Utility has assumed liability for the site, the current owner has asserted a claim against the Utility, or the Utility has otherwise determined it is probable that a claim will be asserted.

The Utility's Diablo Canyon power plant uses a process known as "once through cooling" that takes in water from the ocean to cool the generating facility and discharges the heated water back into the ocean. There is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. In July 2004, the U.S. Environmental Protection Agency ("EPA") issued regulations to implement Section 316(b) intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations provided each facility with a number of compliance options and permitted site-specific variances based on a cost-benefit analysis. The EPA regulations also allowed the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, the California State Water Resources Control Board ("Water Board") issued a proposed policy to address once through cooling. The Water Board's current proposal would require the installation of cooling towers at nuclear facilities by January 1, 2021, unless the installation of cooling towers would conflict with a nuclear safety requirement.

Various parties separately challenged the EPA's regulations and in January 2007, the U.S. Court of Appeals for the Second Circuit ("Second Circuit") issued a decision holding that environmental restoration cannot be used as a compliance option and that site-specific compliance variances based on a cost-benefit test could not be used. The Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and in July 2007, the EPA suspended its regulations. The U.S. Supreme Court is expected to issue a decision by mid-2009 regarding the cost-benefit test. Depending on the form of the final regulations that may ultimately be adopted by the EPA or the Water Board, the Utility may incur significant capital expense to comply with the final regulations, which the Utility would seek to recover through rates. If either the final regulations adopted by the EPA or the Water Board require the installation of cooling towers at Diablo Canyon, and if installation of such cooling towers is not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge.

Legal Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits.

In accordance with SFAS No. 5, "Accounting for Contingencies" PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and adjusted to reflect the impacts of negotiations, discovery settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing such contingencies, PG&E Corporation and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation and the Utility's Current Liabilities - Other in the Consolidated Balance Sheets, and totaled approximately \$72 million at December 31, 2008 and approximately \$78 million at December 31, 2007. After consideration of these accruals, PG&E Corporation and the Utility do not expect losses associated with legal matters would have a material adverse impact on their financial condition and result of operations.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended			
	December 31	September 30	June 30	March 31
2008				
PG&E CORPORATION				
Operating revenues	\$ 3,643	\$ 3,674	\$ 3,578	\$ 3,733
Operating income	545	639	584	493
Income from continuing operations	363	304	293	224
Net income	517	304	293	224
Earnings per common share from continuing operations, basic	0.98	0.83	0.80	0.62
Earnings per common share from continuing operations, diluted	0.97	0.83	0.80	0.62
Net income per common share, basic	1.39	0.83	0.80	0.62
Net income per common share, diluted	1.37	0.83	0.80	0.62
Common stock price per share:				
High	39.20	42.64	40.90	44.95
Low	29.70	36.81	38.09	36.46
UTILITY				
Operating revenues	\$ 3,643	\$ 3,674	\$ 3,578	\$ 3,733
Operating income	548	640	585	493
Net income	329	321	313	236
Income available for common stock	325	318	309	233
2007				
PG&E CORPORATION				
Operating revenues	\$ 3,415	\$ 3,279	\$ 3,187	\$ 3,356
Operating income	448	582	555	529
Income from continuing operations	203	278	269	256
Net income	203	278	269	256
Earnings per common share from continuing operations, basic	0.56	0.77	0.75	0.71
Earnings per common share from continuing operations, diluted	0.56	0.77	0.74	0.71
Net income per common share, basic	0.56	0.77	0.75	0.71
Net income per common share, diluted	0.56	0.77	0.74	0.71
Common stock price per share:				
High	48.56	47.87	50.89	47.71
Low	43.09	42.14	43.90	43.87
UTILITY				
Operating revenues	\$ 3,416	\$ 3,279	\$ 3,187	\$ 3,356
Operating income	453	585	556	531
Net income	206	283	274	261
Income available for common stock	203	279	270	258

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and Pacific Gas and Electric Company ("Utility") is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2008.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Balance Sheets of PG&E Corporation and the Utility as of December 31, 2008 and 2007, and the related Consolidated Statements of Income, Shareholders' Equity, and Cash Flows ended December 31, 2008 for each of the three years in the period ended December 31, 2008. As stated in their report, which is included in this annual report, Deloitte & Touche LLP also has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the “Company”) and of Pacific Gas and Electric Company and subsidiaries (the “Utility”) as of December 31, 2008 and 2007, and the related consolidated statements of income, shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company’s and the Utility’s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s and the Utility’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management’s Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and an opinion on the Company’s and the Utility’s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audits of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and of the Utility as of December 31, 2008 and 2007, and the respective results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in January 2008 the Company and the Utility adopted new accounting standards addressing fair value measurement and an amendment to an interpretation of accounting standards for offsetting amounts related to certain contracts. In 2007, the Company and the Utility adopted a new interpretation of accounting standards for uncertainty in income taxes. In 2006, the Company and the Utility adopted new accounting standards for defined benefit pensions and other postretirement plans and share-based payments.

DELOITTE & TOUCHE LLP

February 19, 2009
San Francisco, CA

Significant Subsidiaries

<u>Parent of Significant Subsidiary</u>	<u>Name of Significant Subsidiary</u>	<u>Jurisdiction of Formation of Subsidiary</u>	<u>Names under which Significant Subsidiary does business</u>
PG&E Corporation	Pacific Gas and Electric Company	CA	Pacific Gas and Electric Company PG&E
Pacific Gas and Electric Company	None		

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-149360 on Form S-3, 333-144498 on Form S-3D, and 333-16253, 333-117930, 333-77149, 333-73054, and 333-129422 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-149361 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 19, 2009, relating to the financial statements and financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company and the effectiveness of PG&E Corporation's and Pacific Gas and Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2008. The report on the financial statements and the effectiveness of the internal control over financial reporting expresses an unqualified opinion and includes for PG&E Corporation and Pacific Gas and Electric Company an explanatory paragraph stating that in January 2008 new accounting standards were adopted for addressing fair value measurement and an amendment to an interpretation of accounting standards for offsetting amounts related to certain contracts, in 2007 a new interpretation of accounting standards for uncertainty in income taxes, and in 2006 new accounting standards for defined benefit pensions and other postretirement plans and share-based payments.

DELOITTE & TOUCHE LLP

February 19, 2009
San Francisco, CA

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION

February 18, 2009

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this corporation for the year ended December 31, 2008, and has recommended to the Board that such financial statements be included in the corporation's Annual Report on Form 10-K for the year ended December 31, 2008, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC A. MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES is hereby authorized to sign on behalf of this corporation and as attorneys in fact for the Chairman, Chief Executive Officer, and President, the Senior Vice President, Chief Financial Officer, and Treasurer, and the Vice President and Controller of this corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President, Corporate Governance and Corporate Secretary of PG&E Corporation, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 18, 2009; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 19th day of February, 2009.

LINDA Y.H. CHENG

Linda Y.H. Cheng

Vice President, Corporate Governance and Corporate Secretary

PG&E CORPORATION

C O R P O R A T E

S E A L

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY**

February 18, 2009

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this company for the year ended December 31, 2008, and has recommended to the Board that such financial statements be included in the company's Annual Report on Form 10-K for the year ended December 31, 2008, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC A. MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES is hereby authorized to sign on behalf of this company and as attorneys in fact for the President and Chief Executive Officer, the Vice President, Finance and Chief Financial Officer, and the Vice President and Controller of this company the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President, Corporate Governance and Corporate Secretary of PACIFIC GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 18, 2009; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 19th day of February, 2009.

LINDA Y.H. CHENG

Linda Y.H. Cheng

Vice President, Corporate Governance and Corporate Secretary
Pacific Gas and Electric Company

C O R P O R A T E

S E A L

POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 18th day of February, 2009.

DAVID R. ANDREWS

David R. Andrews

RICHARD A. MESERVE

Richard A. Meserve

C. LEE COX

C. Lee Cox

MARY S. METZ

Mary S. Metz

PETER A. DARBEE

Peter A. Darbee

FORREST E. MILLER

Forrest E. Miller

MARYELLEN C. HERRINGER

Maryellen C. Herringer

BARBARA L. RAMBO

Barbara L. Rambo

ROGER H. KIMMEL

Roger H. Kimmel

BARRY LAWSON WILLIAMS

Barry Lawson Williams

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Chairman of the Board, Chief Executive Officer, and President (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

PETER A. DARBEE

Peter A. Darbee

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President, Chief Financial Officer, and Treasurer of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President, Chief Financial Officer, and Treasurer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

CHRISTOPHER P. JOHNS

Christopher P. Johns

POWER OF ATTORNEY

STEPHEN J. CAIRNS, the undersigned, Vice President and Controller of PG&E Corporation, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

STEPHEN J. CAIRNS

Stephen J. Cairns

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 18th day of February, 2009.

DAVID R. ANDREWS

David R. Andrews

C. LEE COX

C. Lee Cox

PETER A. DARBEE

Peter A. Darbee

MARYELLEN C. HERRINGER

Maryellen C. Herringer

ROGER H. KIMMEL

Roger H. Kimmel

RICHARD A. MESERVE

Richard A. Meserve

MARY S. METZ

Mary S. Metz

FORREST E. MILLER

Forrest E. Miller

BARBARA L. RAMBO

Barbara L. Rambo

BARRY LAWSON WILLIAMS

Barry Lawson Williams

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as President and Chief Executive Officer (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

PETER A. DARBEE

Peter A. Darbee

POWER OF ATTORNEY

BARBARA L. BARCON, the undersigned, Vice President, Finance and Chief Financial Officer of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in her capacity as Vice President, Finance and Chief Financial Officer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

BARBARA L. BARCON

Barbara L. Barcon

POWER OF ATTORNEY

STEPHEN J. CAIRNS, the undersigned, Vice President and Controller of Pacific Gas and Electric Company, hereby constitutes and appoints HYUN PARK, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, ERIC MONTIZAMBERT, LINDA L. AGERTER, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2008, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 18th day of February, 2009.

STEPHEN J. CAIRNS

Stephen J. Cairns

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Peter A. Darbee, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2008 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

PETER A. DARBEE

Peter A. Darbee
Chairman, Chief Executive Officer, and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2008 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

CHRISTOPHER P. JOHNS

Christopher P. Johns

Senior Vice President, Chief Financial Officer and Treasurer

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Peter A. Darbee, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2008 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

PETER A. DARBEE

Peter A. Darbee
President and Chief Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Barbara L. Barcon, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2008 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

BARBARA L. BARCON

Barbara L. Barcon

Vice President, Finance and Chief Financial Officer

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2008 ("Form 10-K"), I, Peter A. Darbee, Chairman, Chief Executive Officer, and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE

Chairman, Chief Executive Officer, and President

February 24, 2009

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2008 ("Form 10-K"), I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS

Senior Vice President,

Chief Financial Officer and Treasurer

February 24, 2009

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2008 ("Form 10-K"), I, Peter A. Darbee, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

PETER A. DARBEE

PETER A. DARBEE

President and Chief Executive Officer

February 24, 2009

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the quarter ended September 30, 2008 ("Form 10-K"), I, Barbara L. Barcon, Vice President, Finance and Chief Financial Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

BARBARA L. BARCON

BARBARA L. BARCON

Vice President, Finance and Chief Financial Officer

February 24, 2009
