

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, 2007
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)

Title of Each Class	Securities registered pursuant to Section 12(b) of the Act:	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%		American Stock Exchange

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, 2007, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation Common Stock \$15,962 million
Pacific Gas and Electric Company Common Stock Wholly owned by PG&E Corporation

Common Stock outstanding as of February 19, 2008:

PG&E Corporation: 355,749,692 (excluding shares held by a wholly owned subsidiary)
Pacific Gas and Electric Company: 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 2007 Annual Report to Shareholders	Part I (Item 1.A.), Part II (Items 5, 6, 7, 7A, 8 and 9A)
Designated portions of the Joint Proxy Statement relating to the 2008 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

TABLE OF CONTENTS

		Page
	Units of Measurement	iii
	PART I	
Item 1.	Business	1
	General	1
	<i>Corporate Structure and Business</i>	1
	<i>Corporate and Other Information</i>	1
	<i>Employees</i>	1
	Cautionary Language Regarding Forward Looking Statements	1
	PG&E Corporation's Regulatory Environment	3
	<i>Federal Energy Regulation</i>	3
	<i>State Energy Regulation</i>	3
	The Utility's Regulatory Environment	4
	<i>Federal Energy Regulation</i>	4
	<i>State Energy Regulation</i>	5
	<i>Other Regulation</i>	6
	Competition	7
	<i>Competition in the Electricity Industry</i>	7
	<i>Competition in the Natural Gas Industry</i>	8
	Ratemaking Mechanisms	10
	Overview	10
	<i>Electricity and Natural Gas Distribution and Electricity Generation Operations</i>	10
	<i>General Rate Cases</i>	10
	<i>Attrition Rate Adjustments</i>	11
	<i>Cost of Capital Proceedings</i>	11
	<i>Baseline Allowance</i>	11
	<i>Public Purpose and Other Programs</i>	11
	<i>Energy Efficiency Programs</i>	11
	<i>Demand Response Programs</i>	12
	<i>Self-Generation Incentive Program and California Solar Initiative</i>	12
	<i>Low-Income Energy Efficiency Programs and California Alternate Rates for Energy</i>	12
	<i>ClimateSmart™ Program</i>	13
	<i>Rate Recovery of Costs of New Electricity Generation Resources</i>	13
	Overview	13
	<i>Costs Incurred Under New Power Purchase Agreements</i>	13
	<i>Costs of Utility-Owned Generation Resource Projects</i>	14
	<i>DWR Electricity and DWR Revenue Requirements</i>	14
	<i>Electricity Transmission</i>	14
	<i>Transmission Owner Rate Cases</i>	14
	<i>Natural Gas</i>	15
	<i>The Gas Accord</i>	15
	<i>Biennial Cost Allocation Proceeding</i>	16
	<i>Natural Gas Procurement</i>	16
	<i>Interstate and Canadian Natural Gas Transportation and Storage</i>	16
	Electric Utility Operations	17
	<i>Electricity Resources</i>	17
	<i>Owned Generation Facilities</i>	17
	<i>DWR Power Purchases</i>	18
	<i>Third-Party Power Purchase Agreements</i>	19
	<i>Future Long-Term Generation Resources</i>	19
	<i>Electricity Transmission</i>	19
	<i>Electricity Distribution Operations</i>	20
	<i>2007 Electricity Deliveries</i>	21
	<i>Electricity Distribution Operating Statistics</i>	21
	Natural Gas Utility Operations	22
	<i>2007 Natural Gas Deliveries</i>	23
	<i>Natural Gas Operating Statistics</i>	23

	<i>Natural Gas Supplies</i>	24
	<i>Gas Gathering Facilities</i>	25
	<i>Interstate and Canadian Natural Gas Transportation Services Agreements</i>	25
	Environmental Matters	26
	<i>General</i>	26
	<i>Air Quality and Climate Change</i>	27
	<i>Water Quality</i>	27
	<i>Compressor Station Litigation</i>	28
	<i>Endangered Species</i>	29
	<i>Hazardous Waste Compliance and Remediation</i>	29
	<i>Nuclear Fuel Disposal</i>	31
	<i>Nuclear Decommissioning</i>	31
	<i>Electric and Magnetic Fields</i>	32
Item 1A.	Risk Factors	32
Item 1B.	Unresolved Staff Comments	33
Item 2.	Properties	32
Item 3.	Legal Proceedings	33
	<i>Diablo Canyon Power Plant</i>	33
	<i>Complaints Filed by the California Attorney General, City and County of San Francisco</i>	33
	<i>Solano County District Attorney's Office</i>	34
Item 4.	Submission of Matters to a Vote of Security Holders	35
	Executive Officers of the Registrants	35
PART II		
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	38
Item 6.	Selected Financial Data	38
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	39
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	39
Item 8.	Financial Statements and Supplementary Data	39
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	39
Item 9A.	Controls and Procedures	39
Item 9B.	Other Information	39
PART III		
Item 10.	Directors, Executive Officers and Corporate Governance	41
Item 11.	Executive Compensation	42
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters	42
Item 13.	Certain Relationships and Related Transactions, and Director Independence	43
Item 14.	Principal Accountant Fees and Services	43
PART IV		
Item 15.	Exhibits and Financial Statement Schedules	43
	Signatures	49
	Report of Independent Registered Public Accounting Firm	51
	Financial Statement Schedules	52

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, 2007. The Utility had approximately \$36.3 billion of assets at December 31, 2007, and generated revenues of approximately \$13.2 billion in 2007. 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, 2007, PG&E Corporation and its subsidiaries had approximately 20,050 regular employees, including approximately 19,785 regular employees of the Utility. Of the Utility's regular employees, approximately 12,929 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"). The ESC and IBEW collective bargaining agreements expire on December 31, 2008. The SEIU collective bargaining agreement expires on February 28, 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, 2007 ("2007 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, 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," "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 operating costs within authorized levels and recover costs through rates in a timely manner;
- the outcome of regulatory proceedings, including pending and future ratemaking proceedings at the CPUC and the FERC;

- 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;
 - 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 the Utility's Diablo Canyon nuclear generating facilities ("Diablo Canyon"), 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 efficiencies it has recognized from its completed initiatives to improve its business processes and customer service, improve its performance following the October 2007 implementation of new work processes and systems, and identify and successfully implement additional cost-saving measures
 - whether the Utility incurs substantial unanticipated expense to improve the safety and reliability of its electric and natural gas distribution systems;
 - whether the Utility achieves the CPUC's energy efficiency targets and recognize 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 and/or the Utility to access capital markets and other sources of credit in a timely manner on favorable terms;
 - 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 more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see "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 2007 Annual Report that is incorporated by reference and filed as part of Exhibit 13 to this Annual Report on Form 10-K. 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.

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 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, 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 "Ratemaking 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. For more information, see "Regulatory Matters" in the MD&A in the 2007 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., known as the NERC, as the nation's Electric Reliability Organization under the EPAct. 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. Failure of the Utility to comply with FERC-approved electric reliability standards may subject the Utility to penalties. 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.

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.

Prevention of Market Manipulation. The EPAct also gave the FERC broader authority to police and penalizes 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 known as 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.

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 with the implementation of a market framework for electricity generation in which generators and other energy providers were permitted to charge market-based rates for wholesale electricity and the investor-owned utilities’ customers were given the choice to become “direct access” customers by buying energy from an alternate service provider other than the regulated utilities. Among other provisions, Assembly Bill 1890 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 recover their reasonable wholesale procurement costs incurred under a CPUC-approved procurement plan through the establishment of new electricity procurement balancing accounts to allow timely recovery by the utilities of 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 Program, which requires each California retail seller of electricity, except municipal utilities, to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by 2010.
- **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 does retain 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 2007 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 set fees of their own determination. 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 agreements with two large charter cities. 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 then is recovered by the regulated transmission provider in its overall transmission rates.

State. At the state level, Assembly Bill 1890, enacted in 1996, 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 2007 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 and has indicated that it will not set a new date for commencement of MRTU until market participants have had an opportunity to test the final MRTU functionality and have provided feedback to the CAISO. Also, in January 2008, the CPUC staff issued its recommendation to establish a statewide wholesale electricity capacity market to replace the current resource adequacy program. The CPUC is expected to issue a decision on this matter in May 2008. Any changes the CPUC adopts would be subject to the FERC’s 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 scheduled to vote on February 28, 2008 on a proposed decision that concludes the CPUC does not have the authority to reinstate direct access because the DWR still supplies power under the contracts it executed during the energy crisis. The proposed decision states that the CPUC will proactively investigate 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 intends to begin operating in 2008.

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 FERC 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 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 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. In September 2007, applications with the FERC were filed to request authorization to construct the proposed Pacific Connector Gas Pipeline and the Jordan Cove LNG terminal. It is expected that the FERC will issue a decision by the end of 2008.

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 Partners, L.P. PG&E Corporation cannot predict whether Fort Chicago 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, it is anticipated that the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline would begin commercial operation in 2011.

In December 2007, PG&E Corporation entered into a letter of intent with El Paso Corporation to acquire a 25.5% interest in 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. PG&E Corporation's acquisition of an interest in the Ruby Pipeline project is subject to various conditions, including the negotiation and execution of the partnership documents. Subject to obtaining the required regulatory and other approvals, including the approvals of the boards of directors of PG&E Corporation and El Paso Corporation, and after obtaining necessary customer commitments, the Ruby Pipeline is anticipated to be in service in the first quarter of 2011.

Ratemaking Mechanisms

Overview

The Utility's rates for electricity and natural gas utility services are based on its costs of providing service (called cost-of-service ratemaking). Before setting rates, the CPUC and the FERC determine the annual amount of revenue (called 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 (called 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. Cost balancing accounts track differences between the Utility's incurred costs and its authorized revenue requirements, most importantly for energy commodity costs and volumes. 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 objective or fixed standards instead of on the cost of providing service. The primary example is the Utility's customer energy efficiency shareholder incentive mechanism. In September 2007, the CPUC established incentive ratemaking mechanisms applicable to the California investor-owned utilities' implementation of their energy efficiency programs funded for the 2006-2008 and 2009-2011 program cycles. (For more information, see "Public Purpose and Other Programs" below.) Another example is the Core Procurement Incentive Mechanism ("CPIM") under which the Utility's natural gas purchase costs are compared to an aggregate market-based benchmark, and the Utility's shareholders share in the costs or savings outside a tolerance band around the benchmark. (See "Natural Gas Procurement" below.)

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 ("TURN"). On March 15, 2007, the CPUC approved a multi-party settlement agreement to resolve the Utility's 2007 GRC. The decision sets 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. On November 1, 2007, the CPUC denied an application for rehearing of the decision that had been filed by TURN and Aglet Consumer Alliance. Neither TURN nor Aglet filed a petition for appellate review of the denial. For more information, see "Results of Operations – Electric Revenues" in the MD&A in the 2007 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 to be made in 2008, 2009 and 2010. For more information, see "Results of Operations – Electric Revenues" in the MD&A in the 2007 Annual Report.

Cost of Capital Proceedings

The CPUC generally conducts an annual cost of capital 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 for a specific year. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. The Utility's CPUC-authorized capital structure for 2008 consists of 46% long-term debt, 2% preferred stock and 52% common equity. The Utility's CPUC-authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation rate base for 2008 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%. The CPUC is considering various mechanisms that could replace the annual cost of capital proceedings. The CPUC is scheduled to issue a final decision on this issue by April 24, 2008.

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. In addition, California law requires the CPUC to authorize funding for the California Solar Initiative discussed below, and other self-generation programs. In addition to public purpose programs, the CPUC has authorized additional funding for demand response programs. For 2007 expenditures, the CPUC authorized the Utility to collect revenue requirements of approximately \$639 million from electricity customers to fund these electricity public purpose and other programs and to collect revenue requirements of approximately \$82 million from gas customers to fund these natural gas public purpose programs. The CPUC is responsible for authorizing the programs, funding levels and cost recovery mechanisms for the Utility's operation of both energy efficiency and low-income energy efficiency 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 2007, the Utility transferred \$114 million to the CEC for these programs. In 2007, surcharges collected from the Utility's gas customers funded \$7.7 million in gas public interest research and development programs administered by the CEC.

Public purpose programs include:

- **Energy Efficiency Programs.** The CPUC has authorized the Utility's 2006 through 2008 energy efficiency portfolio plans and program and authorized the Utility to recover approximately \$867 million to fund these programs, including funding for evaluation, measurement and verification activities. This increased energy efficiency funding level is part of a larger effort by the State of California to reduce consumption of fossil fuels. The increased funding level is designed to enable both residential and business customers to take more advantage of the diverse mix of energy efficiency programs. In May 2008, the Utility expects to file a new Application with the CPUC seeking approval of energy efficiency programs and funding for the next cycle of energy efficiency, 2009-2011.

In September 2007, the CPUC adopted 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 savings goal over the three-year program

cycle and (2) achieve at least 80% of the individual kWh, kW, and therm savings metric 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 savings goal, the shared rate increases so that 12% of the total verified net benefits will accrue to shareholders and 88% will accrue to customers up to a stated maximum. If the utilities achieve less than 65% of any one of the individual savings metric goals, 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 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.

The utilities must submit two interim claims during the three-year program cycle, subject to verification of the actual amount of net benefits in a final true-up claim. The CPUC will determine for each interim claim whether a utility is entitled to incentives or is required to reimburse customers based on the level of achievement of the CPUC's savings goals on a cumulative-to-date basis. The interim amounts will be calculated using updated estimates and assumptions about the energy savings per energy efficiency measure ("load impact") over the three-year program period and will be reduced based on an assumption that certain customers would have undertaken the energy efficiency activity in the absence of the utilities' energy efficiency program (the "net-to-gross" ratio). The decision, as modified in January 2008, requires that 35% of the incentives or reimbursement obligations calculated for each interim claim be "held back" until completion of measurement studies verifying the actual energy savings for the entire three-year program cycle. The final true-up may result in an adjustment to the prior year's interim claims, but as long as the final measured energy savings are at least 65% of the CPUC savings goals, the utilities will not be required to pay back any incentives earned on an interim basis.

- *Demand Response Programs.* Demand response programs provide financial incentives and other benefits to participating customers to curtail on-peak energy use. The CPUC has authorized approximately \$109 million for 2006 through 2008 demand response programs for the Utility. In addition, the CPUC approved several contracts with third-party demand response providers in 2007. The payments made under the contracts are recovered through a balancing account.

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. 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 has approved a budget of \$83 million for the SGIP program in 2008, of which \$36 million has been allocated to the Utility. The CPUC also established the California Solar Initiative ("CSI") to bring 1,940 MW of solar power on-line by 2017 through the California investor-owned utilities, and authorized the 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 has approved funding of \$78 million in each of 2007 and 2008 to support energy efficiency programs for low-income and fixed-income customers. 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. For 2007, the amount of this subsidy was approximately \$468.6 million (including avoided customer surcharges). In May 2008, the Utility expects to file an application with the CPUC seeking approval of low-income energy efficiency programs and funding for the next cycle of low-income energy efficiency, 2009-2011.

- *The ClimateSmart™ Program.* In 2006, the CPUC approved the ClimateSmart™ program to allow customers to choose to neutralize greenhouse gas emissions associated with their energy use. Customers who choose to enroll in the ClimateSmart™ program will pay a small premium on their monthly utility bill, based on their energy usage, to fund environmental projects aimed at removing carbon dioxide and other greenhouse gases from the air. The Utility estimates that this program, which began at the end of June 2007, will generate approximately \$15 million by December 31, 2009 to fund projects that are expected to reduce greenhouse gas emissions by at least 1.5 million tons.

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). Every other year, each utility must submit a long-term procurement plan covering a ten-year period to the CPUC for approval. In December 2007, the CPUC approved the utilities' long-term procurement plan, 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 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 competitive bidding 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.

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 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 procurement costs.

The authorized revenue requirements for capital costs and non-fuel operating and maintenance costs for Utility-owned generation are addressed in the Utility's GRC. The revenue requirement to recover the initial capital costs for CPUC-approved utility owned generation projects will be recovered through a balancing account, the Utility Generation Balancing Account ("UGBA"), which will track 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.

Costs Incurred Under New Power Purchase Agreements

During 2006-2007, the CPUC approved several power purchase agreements 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—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

During 2006, the CPUC approved three agreements related to Utility-owned generation projects in accordance with the Utility's CPUC approved long-term procurement plan. The CPUC also authorized the amount of revenue requirements that the Utility is authorized to recover related to each project to recover capital costs and non-fuel operations and maintenance costs. For more information, see "Capital Expenditures – New Generation Facilities" in the MD&A in the 2007 Annual Report

In its December 2007 decision on the utilities' long-term procurement plans, for future utility-owned generation projects the CPUC eliminated the limitations it had adopted in 2004 that required the utilities to share half of any construction cost savings with ratepayers while absorbing any cost overruns. Instead, the decision allows the utilities to make flexible proposals for utility-owned generation ratemaking on a case-by-case basis. 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.

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"). A TO rate case is generally held every year and sets 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 "Results of Operations — Electric Operating Revenues" in the MD&A in the 2007 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.

In December 2007, the FERC approved a settlement between the Utility and PacificCorp, both owners of an electric transmission line which is part of the California – Oregon Intertie, and other entities, relating to the termination of agreements that govern electric transmission service over the California – Oregon Intertie. For more information, see "Electric Utility Operations – Electric Transmission" below. As a condition of the settlement, the Utility will lease back a portion of the capacity allocated to PacificCorp from 2008 through 2017 over the eastern 500 KV line between the substation in Malin, Oregon, and the Round Mountain substation located in California. In addition, the Utility's lease payments to PacificCorp will be fully recovered through the Utility's transmission owner rates.

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. The Utility's backbone transmission costs are partly assured of recovery to the extent backbone capacity is subscribed under long-term firm contracts, and to the extent the costs of that contracted capacity are recovered through fixed reservation charges. Core procurement entities (including core customers served by the Utility) are the primary long-term subscribers to backbone capacity. Core customers are allocated approximately 32% of the total backbone capacity on the Utility's system. Core customers pay approximately 71% 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 70% to core customers and 30% to non-core customers. The core portion is protected through a balancing account and therefore represents assured revenues. The non-core portion is subject to volumetric cost recovery 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 core portion is protected through a balancing account and therefore represents assured revenues. Recovery of the non-core portion is subject to volumetric and price risk. The pipeline load balancing

portion 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 47% 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 75% 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 "Risk Management Activities" section of MD&A in the 2007 Annual Report).

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 Energy and Utilities Board 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. In 2007, in conjunction with the settlement of a FERC rate case filed by TransCanada's Gas Transmission Northwest Corporation, which transports Canadian natural gas to California, the Utility agreed to extend its existing contract commitment for a series of multiple-year terms. The FERC approved the settlement in January 2008. The settlement is further discussed 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 2007 represented by each major electricity resource:

Owned generation (nuclear, fossil fuel-fired and hydroelectric facilities)	32%
DWR	25%
Qualifying Facilities/Renewables	20%
Irrigation Districts	3%
Other Power Purchases	20%

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, 2007, 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, 2007, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 90.2%.

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 2007 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 48 days. The Utility will replace the steam generators in Unit 2 during the scheduled refueling outage which began on February 4, 2008 and will replace the steam generators in Unit 1 during the scheduled refueling outage to begin January 2009. Due to this additional work, each of these refueling outages is expected to last approximately 76 days. (The capital

expenditures necessary to complete these projects are discussed further in the “Capital Expenditures” section of MD&A in the 2007 Annual Report.) The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2008	2009	2010	2011	2012
Unit 1					
Refueling	-	January	October		April
Duration (days)	-	76	35		30
Startup	-	April	November		May
Unit 2					
Refueling	February	October	-	May	
Duration (days)	76	35	-	30	
Startup	April	November	-	June	

In addition, as discussed below under “Environmental Matters — Nuclear Fuel Disposal,” the Utility is constructing an on-site dry cask storage facility to store the spent nuclear fuel that is expected to be completed in 2008. To provide another storage alternative in the event that construction of the dry cask storage facility is delayed, 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 the Utility is unable to complete the dry cask storage facility, or if construction is delayed 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 68 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 but three of the Utility's powerhouses are licensed by the FERC, with license terms between 30 and 50 years. In the last five years, the FERC renewed six hydroelectric licenses with a total of 699 MW of hydroelectric power. The Utility is in the process of renewing licenses for projects with approximately 1,314 MW of additional hydroelectric power. Although the original licenses associated with 917 MW of the 1,314 MW have expired, the licenses are automatically renewed each year until completion of the relicensing process. Licenses associated with approximately 2,569 MW of hydroelectric power will expire between 2013 and 2043.

DWR Power Purchases

During 2007, electricity from the DWR contracts allocated to the Utility provided approximately 25% 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. During 2007, the DWR terminated a long-term power purchase agreement it had with Calpine Corporation over the objections of the Utility and other interested parties. As a result, the Utility has had to purchase replacement power on behalf of its customers at a significantly higher price. The Utility expects that the amount of power supplied under the DWR's contracts will diminish in the future as the contracts expire or are terminated. For more information regarding the DWR contracts, see Note 17: Commitments and Contingencies – Third-Party Power Purchase Agreements, of the Notes to the Consolidated Financial Statements in the 2007 Annual Report.

Third-Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements. As of December 31, 2007, the Utility had agreements with 257 QFs for approximately 4,097 MW that are in operation. Agreements for approximately 3,754 MW expire at various dates between 2008 and 2028. QF power purchase agreements for approximately 343 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 4,097 MW consists of approximately 2,524 MW from cogeneration projects, 580 MW from wind projects and 994 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar, and hydroelectric. QF power purchase agreements accounted for approximately 20%, 20%, and 22% of the Utility's 2007, 2006, and 2005 electricity sources, respectively. No single QF accounted for more than 5% of the Utility's 2007, 2006, or 2005 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 2008 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 3% of the Utility's 2007 electricity sources, approximately 6% of the Utility's 2006 electricity sources and 5% of the Utility's 2005 electricity sources.

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, wind, solar, and geothermal energy) by at least 1% of its retail sales, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2010. The CPUC has adopted "flexible compliance" rules, which allow deliveries above interim required levels to be carried forward, permit a retail seller to maintain a procurement deficit for up to three years following the year in which the deficit is incurred, and may, in certain cases, provide allowable reasons for noncompliance. During 2007, the Utility entered into 9 new renewable power purchase agreements, representing approximately 3,000 GWh per year of renewable generation that will help the Utility to meet its goals. The Utility expects to use the flexible compliance Rules to meet the 2010 requirement. Failure to satisfy the targets may result in a penalty of five cents per kWh, with an annual penalty cap of \$25 million. The exact amount of any penalty and conditions under which it would be applied are subject to the CPUC's review of whether supply-side factors or other circumstances caused the under-delivery.

Long Term Power Purchase Agreements. In December 2007, the CPUC approved, with several modifications, the long-term electricity procurement plans ("LTTPs") of the California investor-owned electric utilities covering the 10-year period from 2007 through 2016. Each utility is required to submit an LTTP designed to reduce greenhouse gas emissions and uses 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). The decision notes that if a previously approved contract is terminated before the generation project is built, the utilities will retain the procurement authority for the MWs subject to the terminated contract. At the end of the solicitation or request-for-offer ("RFO") process, the utilities must justify why each bid was selected or rejected. Utilities can acquire ownership of new conventional generation resources in the utilities' competitive RFO process only through turnkey and engineering, procurement, and construction arrangements proposed by third parties. The utilities are required to submit revised LTTPs reflecting the changes required by the CPUC within 90 days of the date the decision is mailed.

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 2007 Annual Report.

Future Long-Term Generation Resources

On December 20, 2007, the CPUC issued a decision that approves, with several modifications, the California investor-owned utilities' long-term electricity procurement plan covering procurement during 2007-2016. The CPUC forecasts that the Utility will need to obtain an additional 800 to 1,200 MW of new conventional generation by 2015 based on forecasts prepared by the CEC. The decision finds that in earlier years (i.e., 2007-2013), the Utility has a surplus of resources and in 2014 the forecast shows a small need for 66 MW.

The decision allows the utilities to acquire ownership of new conventional generation resources only through turnkey and engineering, construction, and procurement ("EPC") arrangements proposed by third parties. The decision prohibits the utilities from submitting bids for utility-build generation in their respective RFOs until questions can be resolved about how to compare utility-owned generation bids with bids from independent power producers. The decision also permits utility-owned generation projects to be proposed 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 expand existing facilities, (4) to take advantage of a unique and fleeting opportunity (such as a bankruptcy settlement) and (5) to meet unique reliability needs.

Electricity Transmission

At December 31, 2007, the Utility owned 18,680 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 54,709 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 140,684 circuit miles of distribution lines and substations with a capacity of 26,370 MVA. In 2007, the Utility delivered 86,179 GWh to its customers, including 6,723 GWh delivered to direct access customers. The Utility is interconnected with electric power systems in the Western Electricity Coordinating Council, which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

In 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 has 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."

In April 2006, the Utility completed a new 230-kV transmission line from Redwood City to Brisbane, known as the Jefferson-Martin 230-kV Line. The completed transmission line provides additional transmission system reliability in San Francisco and northern San Mateo County. As result of the completion of the transmission line, the Utility was able to retire the Hunters Point power plant in San Francisco. 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 increase access to southern California and Southwest 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.

In December 2007, the FERC approved a settlement between the Utility and PacifiCorp, both owners of an electric transmission line which is part of the California – Oregon Intertie ("COI"), as well as other entities, relating to the termination of agreements that govern transmission service over the COI. The COI is a major electric transmission link connecting California with the Pacific Northwest and vital to electric grid reliability. The settlement provides for the shared usage and coordinated planning, operation, and maintenance of the eastern 500 kV transmission line between the Malin substation in Oregon and the Round Mountain substation in California. As a result of the settlement, the Utility and PacifiCorp will each have rights to half of the capacity on the eastern 500 kV transmission line between the Malin and Round Mountain substations for a twenty year period. In addition, the Utility will lease back a portion of the capacity allocated to PacifiCorp for the first ten years. The settlement allows the Utility to continue its rights to all existing available transmission service over the eastern 500 KV line between the Malin and Round Mountain substations through December 31, 2011; these rights decrease to half of the total capacity by 2018. The settlement also provides that the Utility's lease payments to PacifiCorp will be fully recovered through the Utility's transmission owner rates.

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 140,684 circuit miles of distribution lines (of which approximately 19% are underground and approximately 81% are overhead). There are 93 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 605 distribution substations and 110 low-voltage distribution substations. The 54 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 will enable the Utility to measure usage on an hourly basis for electricity and on a daily basis for natural gas, which will 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. On December 12, 2007, the Utility filed an application with the CPUC requesting approval 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 entitled "Capital Expenditures" in the MD&A portion of the 2007 Annual Report.)

2007 Electricity Deliveries

The following table shows the percentage of the Utility's total 2007 electricity deliveries represented by each of its major customer classes:

Total 2007 Electricity Delivered: 86,179 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 2003 to 2007 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2007	2006	2005	2004	2003
Customers (average for the year):					
Residential	4,464,483	4,417,638	4,353,458	4,366,897	4,286,085
Commercial	521,732	515,297	509,786	509,501	493,638
Industrial	1,261	1,212	1,271	1,339	1,372
Agricultural	80,366	79,006	78,876	80,276	81,378
Public street and highway lighting	29,643	28,799	28,021	27,176	26,650
Other electric utilities	2	4	4	3	4
Total ⁽¹⁾	5,097,487	5,041,956	4,971,416	4,985,192	4,889,127
Deliveries (in GWh):(2)					
Residential	30,796	31,014	29,752	29,453	29,024
Commercial	33,986	33,492	32,375	32,268	31,889
Industrial	15,159	15,166	14,932	14,796	14,653
Agricultural	5,402	3,839	3,742	4,300	3,909
Public street and highway lighting	833	785	792	2,091	605
Other electric utilities	3	14	33	28	76
Subtotal	86,176	84,310	81,626	82,936	80,156
California Department of Water Resources (DWR)	(21,193)	(19,585)	(20,476)	(19,938)	(23,554)
Total non-DWR electricity	64,986	64,725	61,150	62,998	56,602
Revenues (in millions):					
Residential	\$ 4,580	\$ 4,491	\$ 3,856	\$ 3,718	\$ 3,671
Commercial	4,484	4,414	4,114	4,179	4,440
Industrial	1,252	1,293	1,232	1,204	1,410
Agricultural	664	483	446	491	522
Public street and highway lighting	78	72	66	71	69
Other electric utilities	85	59	4	22	24

Subtotal	11,143	10,812	9,718	9,685	10,136
DWR	(2,229)	(2,119)	(1,699)	(1,933)	(2,243)
Direct access credits	—	—	—	—	(277)
Miscellaneous(3)	215	261	235	(248)	(52)
Regulatory balancing accounts	352	(202)	(327)	363	18
Total electricity operating revenues	\$ 9,481	\$ 8,752	\$ 7,927	\$ 7,867	\$ 7,582
Other Data:					
Average annual residential usage (kWh)	6,898	7,020	6,834	6,744	6,772
Average billed revenues (cents per kWh):					
Residential	14.87	14.48	12.96	12.62	12.65
Commercial	13.19	13.18	12.71	12.95	13.92
Industrial	8.26	8.53	8.25	8.14	9.62
Agricultural	12.29	12.58	11.92	11.41	13.35
Net plant investment per customer	\$ 3,418	\$ 3,148	\$ 2,966	\$ 2,790	\$ 2,689

- (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.
- (3) Miscellaneous revenues in 2003 include a \$125 million reduction due to refunds to electricity customers from generation-related revenues in excess of generation-related costs.

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 39 of California's 58 counties and includes most of northern and central California. In 2007, the Utility served approximately 4.3 million natural gas distribution customers. The total volume of natural gas throughput during 2007 was approximately 875 Bcf.

As of December 31, 2007, the Utility's natural gas system consisted of 41,805 miles of distribution pipelines, 6,393 miles of backbone and local transmission pipelines, and three storage facilities. The Utility's distribution network connects to the Utility's transmission and storage system at approximately 2,200 major interconnection points. 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 system. The Utility's Line 300, which interconnects with the U.S. Southwest and California-Oregon 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 at the California-Arizona border of approximately 1.1 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 2.0 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.

In September 2007, the Utility announced that it had entered into an agreement with Gill Ranch Storage, LLC, a subsidiary of Northwest Natural Gas Company, to develop an underground natural gas storage facility near Fresno, California. The new storage facility would provide approximately 20 Bcf of total capacity once the initial phase is completed, expected in 2010. On February 4, 2008, the parties executed a Joint Project Agreement which provides the Utility a 25% interest in the initial project phase. Development of the project is subject to CPUC issuance of a Certificate of Public Convenience and Necessity and an environmental review to be conducted by the CPUC under the California Environmental Quality Act. The parties plan to file an application with the CPUC in May 2008.

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 2007, core customers represented more than 99% of the Utility's total customers and 38% of its total natural

gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and 62% 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 2006 California Gas Report forecasts average annual growth in the Utility's natural gas deliveries (for core customers and non-core transportation) of approximately 1.3% for the years 2006 through 2025. 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.

2007 Natural Gas Deliveries

The following table shows the percentage of the Utility's total 2007 natural gas deliveries represented by each of the Utility's major customer classes:

Total 2007 Natural Gas Deliveries: 875 Bcf

Residential Customers	26%
Transport-only Customers (non-core)	62%
Commercial Customers	12%

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2003 through 2007 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2007	2006	2005	2004	2003
Customers (average for the year):					
Residential	4,030,499	3,989,331	3,929,117	3,812,914	3,744,011
Commercial	223,330	220,024	216,749	215,547	208,857
Industrial	958	988	962	2,178	1,988
Other gas utilities	6	6	6	6	6
Total	4,254,793	4,210,349	4,146,834	4,030,645	3,954,862
Gas supply (MMcf):					

Purchased from suppliers in:

Canada	199,870	202,274	204,884	205,180	196,278
California	(23,065)	(13,401)	(18,951)	(9,108)	(7,421)
Other states	101,271	103,658	103,237	103,801	102,941
Total purchased	278,076	292,531	289,170	299,873	291,798
Net (to storage) from storage	(1,120)	4,359	(3,659)	(532)	1,359
Total	276,955	296,890	285,511	299,341	293,157
Utility use, losses, etc. (1)	(12,760)	(27,610)	(14,312)	(19,287)	(14,307)
Net gas for sales	264,196	269,280	271,199	280,054	278,850
Bundled gas sales (MMcf):					
Residential	196,092	196,092	194,108	201,601	198,580
Commercial	67,293	73,178	77,056	78,080	79,891
Industrial		10	35	373	379
Other gas utilities					
Total	264,196	269,280	271,199	280,054	278,850
Transportation only (MMcf):	605,259	559,270	572,869	597,706	525,353
Revenues (in millions):					
Bundled gas sales:					
Residential	\$ 2,378	\$ 2,452	\$ 2,336	\$ 1,944	\$ 1,836
Commercial	766	859	885	712	697
Industrial					1
Other gas utilities					1
Miscellaneous	88	121	(22)	(29)	(31)
Regulatory balancing accounts	186	40	340	316	68
Bundled gas revenues	3,417	3,472	3,539	2,943	2,572
Transportation service only revenue	340	315	237	270	284
Operating revenues	\$ 3,757	\$ 3,787	\$ 3,776	\$ 3,213	\$ 2,856
Selected Statistics:					
Average annual residential usage (Mcf)	49	49	49	53	53
Average billed bundled gas sales revenues per Mcf:					
Residential	\$ 12.07	\$ 12.50	\$ 12.04	\$ 9.64	\$ 9.25
Commercial	11.38	11.73	11.48	9.12	8.73
Industrial		1.03	0.61	(0.56)	2.48
Average billed transportation only revenue per Mcf	0.56	0.56	0.42	0.45	0.54
Net plant investment per customer	\$ 1,375	\$ 1,304	\$ 1,262	\$ 1,266	\$ 1,261

(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 2007, the Utility purchased approximately 278,076 Mcf of natural gas (net of the sale of excess supply) from 67 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 11% of the total natural gas volume the Utility purchased during 2007.

The following table shows the total volume and the average price of natural gas in dollars per Mcf 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 2007, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2007		2006		2005		2004		2003	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	199,870	\$ 6.63	202,274	\$ 6.27	204,884	\$ 7.12	205,180	\$ 5.37	196,278	\$ 4.73
California (1)	(23,065)	\$ 6.77	(13,401)	\$ 7.04	(18,951)	\$ 7.70	(9,108)	\$ 4.89	(7,421)	\$ 3.39
Other states (substantially all U.S. southwest)	101,271	\$ 6.30	103,658	\$ 6.51	103,237	\$ 7.10	103,801	\$ 5.44	102,941	\$ 4.63
Total/weighted average	278,076	\$ 6.50	292,531	\$ 6.32	289,170	\$ 7.07	299,873	\$ 5.41	291,798	\$ 4.73

(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 2007, 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 117.26 miles of gas gathering pipelines. The Utility receives gas well production at approximately 230 metering facilities. The Utility's gas gathering system is geographically dispersed and is located in 8 California counties. Approximately 132 MMcf per day of natural gas produced in northern California was delivered into the Utility's gas gathering system during 2007.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2007, approximately 60% 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 2007, approximately 34% 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 2007, 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, 2007 (In millions)
TransCanada NOVA Gas Transmission, Ltd.	12/31/2009 ⁽¹⁾	619	\$29.5
TransCanada PipeLines Ltd., B.C. System	10/31/2009	611	15.7
Gas Transmission Northwest Corporation	10/31/2009	610	89.6
Transwestern Pipeline Company	03/31/2010	150	15.9
El Paso Natural Gas Company (2)	Various	252	17.2
Kern River Gas Transmission Company(3)	2/28/2007	29	0.4

- (1) A small portion (23 MDth/d) of the Utility's capacity is due to expire on October 31, 2009.
- (2) As of December 31, 2007, the Utility had four active contracts with El Paso with expiration dates ranging from February 29, 2008 to June 30, 2012.
- (3) This contract was not renewed.

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 Annual 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.

The settlement sets rates on the GTN pipeline for a minimum term of five years commencing January 1, 2007, and provides for substantial refunds to the Utility and other shippers for the higher rates paid since that time. The Utility estimates it will receive refunds on behalf of customers of approximately \$24 million by early April 2008. For contract commitments extending beyond December 31, 2011, the Utility will be obligated to pay the then-effective GTN rate as set by the FERC.

In addition, in December 2007, the Utility entered into an agreement to subscribe for 375 MDth per day of firm service rights on the proposed Ruby Pipeline for a 15-year term commencing in 2011, when the pipeline is proposed to be placed into service. The Utility's commitment is contingent upon the satisfaction of certain conditions precedent, including CPUC approval. (For more information, see "Competition" above.) The Utility expects the CPUC will issue a decision by the end of 2008.

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. Ten percent of any net insurance recoveries associated with hazardous waste remediation sites is assigned to the Utility's customers. The balance of any insurance recoveries (90%) is 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 is 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.

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 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.

The Utility's existing and forecast emissions of climate-changing "greenhouse gases," or GHGs, are relatively low compared to average emissions by other electric utilities and generators in the country, but the Utility anticipates that it will be affected by the increasing attention of the federal and state government to the control of GHGs is gaining increasing attention. 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, in 2006 California enacted Assembly Bill 32 ("AB 32"), the California Global Warming Solutions Act of 2006, to address climate change. AB 32 establishes a regulatory program and schedule to gradually reduce GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. AB 32 also authorizes the California Air Resources Board ("CARB") to monitor and enforce compliance with the GHG reduction program and to consider implementing market-based mechanisms, including trading of GHG emissions allowances. Pursuant to AB 32, on December 6, 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 reduction goals applicable to the utility sector or individual utilities within the utility sector. The CARB also adopted a GHG reporting regulation that will require reporting of 2008 GHG emissions in 2009. The Utility will be required to submit verified GHG emissions reports under CARB's reporting regulation. AB 32 requires CARB to adopt a Scoping Plan by January 2, 2009 for achieving the maximum technologically feasible and cost-effective GHG reductions to meet the 2020 reduction target.

California Senate Bill 1368, also 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.

The new California legislation, 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. These laws could require the Utility to replace equipment, install additional pollution controls, purchase various emission allowances or curtail operations. Although associated costs and capital expenditures could be material, the Utility expects that it will recover these 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.

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 meeting on July 10, 2003, 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.

In July 2004, the U.S. Environmental Protection Agency ("EPA") published regulations under Section 316(b) of the Clean Water Act that apply to existing electricity generation facilities that use over 50 million gallons of water per day, which typically include some form of "once-through" cooling in which water from natural bodies of water is used to cool a generating facility and the heated water is discharged back into the source. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The EPA regulations are intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations allow site-specific compliance measures if a facility's cost of compliance is significantly greater than either the benefits to be achieved or the compliance costs considered by the EPA. The EPA regulations also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, in June 2006, the California State Water Resources Control Board ("Water Board") published a draft policy for California's implementation of Section 316(b) that proposes to eliminate the EPA's site-specific compliance options, although the draft state policy would permit environmental restoration as a compliance option for nuclear facilities if the installation of cooling towers would conflict with a nuclear safety requirement. Various parties separately challenged the EPA's regulations in court, and the cases were consolidated in U.S. Court of Appeals for the Second Circuit ("Second Circuit"). In January 2007, the Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost-benefit test could not be used to comply with performance standards or to obtain a variance from the standards. The Second Circuit also ruled that environmental restoration cannot be used to comply with the standard. Petitions seeking Supreme Court review of the Second Circuit's decision are pending, and the EPA has suspended its regulations. It is uncertain when the EPA will issue revised regulations, whether the Supreme Court will accept review of the Second Circuit decision, how judicial developments will affect the EPA's revised regulations; how judicial developments and EPA's revised regulations will affect the Water Board's proposed policy, and when the Water Board will issue its final policy. Depending on the nature 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.

Compressor Station Litigation

Several lawsuits have been filed against the Utility alleging that exposure to chromium at or near the Utility's natural gas compressor stations caused personal injuries, wrongful deaths or other injuries. During 2006, the Utility entered into a settlement

agreement to resolve most of these claims. Pursuant to the settlement agreement, in April 2006 the Utility released \$295 million from escrow for payment to approximately 1,100 plaintiffs. Three complaints, filed by approximately 125 plaintiffs who did not participate in the settlement, are still pending in the Superior Court for the County of Los Angeles. During 2007 some individual plaintiffs' claims were dismissed based on the applicable statute of limitations. Also, during 2007 the Utility agreed to settle with the remaining plaintiffs, subject to execution of final documentation and court approval of the settlement of the minor plaintiffs' claims which is expected to occur during the first half of 2008. PG&E Corporation and the Utility do not expect that the settlement will have a material adverse effect on their financial condition or results of operations.

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 generation facilities and most of its 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. Preliminary remedial investigations are underway, with agency approval of a remediation plan expected by second quarter 2009. The Utility estimates that it will spend approximately \$16.6 million in 2008 and approximately \$22.7 million in 2009 for these activities.

In addition, the federal Toxic Substances Control Act regulates the use, disposal and clean-up of polychlorinated biphenyls, or 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 42 sites, is potentially liable for remediation of an additional 33 sites, and is not liable for remediation at the remaining 20 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 42 sites for which the Utility is liable. The Utility spent approximately \$7 million in 2007 and expects to spend approximately \$25 million in 2008 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. The Utility is implementing a new program to analyze potential liability for remediation at the 33 additional sites. 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 six 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.

In addition, the Utility has been named as a defendant in several civil lawsuits 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. In 2006, the Utility took interim measures to control movement of the Hinkley plume, and evaluated options to remediate the plume. At the Topock gas compressor station, located near Needles, California, hexavalent chromium has been detected in samples taken from groundwater monitoring wells located approximately 65 feet from the Colorado River, which is adjacent to the site. The Utility, in cooperation with the California Department of Toxic Substances Control, other state agencies and appropriate federal agencies, has implemented interim measures including a system of extractions wells and a treatment plant designed to prevent movement of the plume toward the river. In addition the Utility is working with the agencies to develop a long-term plan to ensure that the hexavalent chromium does not affect the Colorado River. In 2007, the Utility spent approximately \$23 million on the interim measures and for work on the longer term site solution. The Utility plans to continue these activities in 2008 and to work toward the development of a final plan to address the plume in 2008. The Utility currently estimates that it will spend at least \$20 million in 2008 for remediation activities at Topock and \$14 million in 2008 for remediation activities at Hinkley. 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.

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 reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, and considers 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 reasonably 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 environmental remediation liability of approximately \$528 million at December 31, 2007 and approximately \$511 million at December 31, 2006. The Utility's undiscounted future costs could increase to as much as \$834 million if necessary remediation is greater than anticipated.

For more information about environmental remediation liabilities, see Note 17 of the Notes to the Consolidated Financial Statements in the 2007 Annual Report.

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 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 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. On January 15, 2008, the NRC decided to hold hearings on whether it provided a complete list of the references upon which it relied to find that there would not be a significant environmental impact and whether it sufficiently addressed the impacts on land and the local economy of a potential terrorist attack. It is expected that the NRC will issue a final decision in the third quarter of 2008.

The Utility expects to complete the dry cask storage facility and begin loading spent fuel in 2008. If the Utility is unable to complete the dry cask storage facility, if operation of the facility is delayed beyond 2010, or if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and continued until such time as additional safe storage for spent fuel is made available.

The Utility and other nuclear power plant owners have sued the DOE for breach of contract. The Utility seeks to recover its costs to develop on-site storage at Diablo Canyon and Humboldt Bay Unit 3. 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. The Utility appealed to the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenged the U.S. Court of Federal Claims' finding that the Utility would have incurred some of the costs for the on-site storage facilities even if the DOE had complied with the contract. A decision on the appeal is expected by the end of 2008. The Utility will seek to recover costs incurred after 2004 in future lawsuits against the DOE. Any 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 this appeal or the amount of any additional awards the Utility may receive. If the U.S. Court of Federal Claims' decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for on-site storage facilities from the DOE. However, reasonably incurred costs related to the on-site storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

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 ("NDCTP"), 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. 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 2007 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 2007 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 1B. Unresolved Staff Comments

Not applicable.

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" above. 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 buildings in San Francisco, California. The Utility leases approximately 120,000 square feet of the approximate 1.7 million square feet of office space. 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 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 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 California State Water Resources Control 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" in this report.

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 U.S. Court of Appeals for the Ninth Circuit ("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 May 13, 2008.

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.

Solano County District Attorney's Office

In a letter dated July 11, 2007, the Solano County District Attorney's Office stated its intention to file a civil complaint against the Utility for record-keeping violations related to an underground storage tank at the Utility's service center in Vallejo, California. The letter attached a copy of the draft complaint, which detailed a series of alleged California Health and Safety Code record-keeping violations, some of which date back to 2004. Alleged violations include failing to complete inspections, testing, and certifications, and to make records available to the County. Under the California Health and Safety Code, penalties of up to \$5,000 per day for each violation may be assessed. The draft complaint also seeks penalties for unfair and unlawful business practices under California Business and Professions Code Section 17200, under which penalties of up to \$2,500 per violation may be assessed. There

are no allegations related to the discharge of any hazardous substances. The Utility is investigating the allegations and has entered into discussions with the District Attorney. The Utility believes that the ultimate outcome of this matter would not result in a material adverse effect on its 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, 2008, are as follows:

Name	Age	Position
Peter A. Darbee	55	Chairman of the Board, Chief Executive Officer, and President
Kent M. Harvey	49	Senior Vice President and Chief Risk and Audit Officer
Christopher P. Johns	47	Senior Vice President, Chief Financial Officer, and Treasurer
Nancy E. McFadden	49	Senior Vice President, Public Affairs
William T. Morrow	48	President and Chief Executive Officer, Pacific Gas and Electric Company
Hyun Park	46	Senior Vice President and General Counsel
Greg S. Pruett	50	Senior Vice President, Corporate Relations
Rand L. Rosenberg	54	Senior Vice President, Corporate Strategy and Development
John R. Simon	43	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, 2008, 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 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 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
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 Senior Advisor and Deputy Chief of Staff, Office of Governor Gray Davis	March 1, 2007 to present June 20, 2007 to present September 26, 2005 to February 28, 2007 November 13, 2003 to November 30, 2005 May, 2001 to November, 2003

William T. Morrow	President and Chief Executive Officer, Pacific Gas and Electric Company	July 1, 2007 to present
	President and Chief Operating Officer, Pacific Gas and Electric Company	August 1, 2006 to June 30, 2007
	Chief Executive Officer, Europe, Vodafone Group PLC (a global mobile telecommunications company)	May 1, 2006 to July 31, 2006
	President, Vodafone KK, Japan	April 1, 2005 to April 30, 2006
	Chief Executive Officer, Vodafone UK, Ltd.	February 1, 2004 to March 31, 2005
Hyun Park	President, Japan Telecom Holdings Co., Inc.	December 21, 2001 to January 31, 2004
	Senior Vice President and General Counsel	November 13, 2006 to present
	Vice President, General Counsel, and Secretary, Allegheny Energy, Inc. (an investor-owned utility company headquartered in Pennsylvania)	April 5, 2005 to October 17, 2006
Greg S. Pruett	Senior Vice President, General Counsel, and Secretary, Sithe Energies, Inc.	March 2000 to February 2005
	Senior Vice President, Corporate Relations	November 1, 2007 to present
	Vice President, Corporate Relations	March 1, 2007 to October 31, 2007
	Vice President, Communications and Marketing, American Gas Association	April 10, 2006 to February 23, 2007
	Chief Public Affairs Officer, Bechtel National, Inc.	June 12, 2004 to September 12, 2005
Rand L. Rosenberg	Vice President, Corporate Communications, PG&E Corporation	January 1, 1998 to September 12, 2003
	Senior Vice President, Corporate Strategy and Development	November 1, 2005 to present
	Executive Vice President and Chief Financial Officer, Infospace, Inc.	September 2000 to January 20, 2001
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, Pacific Gas and Electric Company	April 16, 2007 to present
	Executive Vice President, Global Human Capital, TeleTech Holdings, Inc.	March 21, 2006 to April 13, 2007
	Senior Vice President, Human Capital, TeleTech Holdings, Inc.	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, 2008, are as follows:

Name	Age	Position
Peter A. Darbee	55	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation
William T. Morrow	48	President and Chief Executive Officer
Thomas E. Bottorff	54	Senior Vice President, Regulatory Relations
Helen Burt	51	Senior Vice President and Chief Customer Officer
Christopher P. Johns	47	Senior Vice President and Treasurer
John S. Keenan	59	Senior Vice President and Chief Operating Officer
Patricia M. Lawicki	47	Senior Vice President and Chief Information Officer
Nancy E. McFadden	49	Senior Vice President, Public Affairs
Hyun Park	46	Senior Vice President and General Counsel, PG&E Corporation
Greg S. Pruett	50	Senior Vice President, Corporate Relations, PG&E Corporation
Edward A. Salas	51	Senior Vice President, Engineering and Operations
John R. Simon	43	Senior Vice President, Human Resources
Geisha J. Williams	46	Senior Vice President, Energy Delivery
G. Robert Powell	44	Vice President, Chief Financial Officer, and Controller
Fong Wan	46	Vice President, Energy Procurement

All officers of the Utility serve at the pleasure of the Board of Directors. During the past five years through February 20,

2008, 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	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation	September 19, 2007 to present
	Chairman of the Board and Chief Executive Officer, PG&E Corporation	January 1, 2006 to September 19, 2007
	Chairman of the Board, Pacific Gas and Electric Company	January 1, 2006 to May 31, 2007
	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation	January 1, 2006 to June 30, 2006
	President and Chief Executive Officer, PG&E Corporation	January 1, 2005 to December 31, 2005
William T. Morrow	Senior Vice President and Chief Financial Officer, PG&E Corporation	July 9, 2001 to December 31, 2004
	President and Chief Executive Officer	July 1, 2007 to present
	President and Chief Operating Officer	August 1, 2006 to June 30, 2007
	Chief Executive Officer, Europe, Vodafone Group PLC (a global mobile telecommunications company)	May 1, 2006 to July 31, 2006
	President, Vodafone KK, Japan	April 1, 2005 to April 30, 2006
Thomas E. Bottorff	Chief Executive Officer, Vodafone UK, Ltd.	February 1, 2004 to March 31, 2005
	President, Japan Telecom Holdings Co., Inc.	December 21, 2001 to January 31, 2004
	Senior Vice President, Regulatory Relations	October 14, 2005 to present
	Senior Vice President, Customer Service and Revenue	March 1, 2004 to October 13, 2005
	Vice President, Customer Service	June 1, 1999 to February 29, 2004
Helen Burt	Senior Vice President and Chief Customer Officer	January 9, 2006 to present
	Vice President, Electric Transmission	July 1, 2005 to January 8, 2006
	Vice President, Distribution Asset Management, American Electric Power	February 1, 2004 to June 30, 2005
	Senior Vice President, Power and Gas, UMS Group, Inc.	October 1, 2001 to January 31, 2004
Christopher P. Johns	Senior Vice President and Treasurer	June 1, 2007 to present
	Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation	October 4, 2005 to present
	Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation	October 1, 2005 to May 31, 2007
	Senior Vice President, Chief Financial Officer, and Controller, PG&E Corporation	January 1, 2005 to October 3, 2005
	Senior Vice President and Controller, PG&E Corporation	September 19, 2001 to December 31, 2004
Patricia M. Lawicki	Senior Vice President and Chief Information Officer	November 1, 2007 to present
	Vice President and Chief Information Officer	January 12, 2005 to October 31, 2007
	Vice President, Chief Information Officer, NiSource, Inc.	April 23, 2003 to January 7, 2005
John S. Keenan	Senior Vice President and Chief Operating Officer	January 1, 2008 to present
	Senior Vice President, Generation and Chief Nuclear Officer	December 19, 2005 to December 31, 2007
	Vice President, Fossil Generation, Progress Energy	November 10, 2003 to December 18, 2005
	Vice President, Brunswick Nuclear Plant, Progress Energy	May 1, 1998 to November 9, 2003
Nancy E. McFadden	Senior Vice President, Public Affairs	June 20, 2007 to present
	Senior Vice President, Public Affairs, PG&E Corporation	March 1, 2007 to present
	Vice President, Governmental Relations	September 26, 2005 to February 28, 2007
	Chairperson, California Medical Assistance Commission	November 13, 2003 to November 30, 2005
	Senior Advisor and Deputy Chief of Staff, Office of Governor Gray Davis	May 2001 to November 2003

Hyun Park	Senior Vice President and General Counsel, PG&E Corporation Vice President, General Counsel, and Secretary, Allegheny Energy, Inc. (an investor-owned utility company headquartered in Pennsylvania)	November 13, 2006 to present April 5, 2005 to October 17, 2006
	Senior Vice President, General Counsel, and Secretary, Sithe Energies, Inc.	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	November 1, 2007 to present March 1, 2007 to October 31, 2007 April 10, 2006 to February 23, 2007
	Chief Public Affairs Officer, Bechtel National, Inc.	June 12, 2004 to September 12, 2005
	Vice President, Corporate Communications, PG&E Corporation	January 1, 1998 to September 12, 2003
Edward A. Salas	Senior Vice President, Engineering and Operations Staff Vice President, Network Planning, Verizon Wireless, Basking Ridge, N.J.	April 11, 2007 to present May 2004 to April 2007
	Contractor, Verizon Wireless, Local Number Portability Implementation	May 2003 to April 2004
John R. Simon	Senior Vice President, Human Resources	April 16, 2007 to present
	Senior Vice President, Human Resources, PG&E Corporation	April 16, 2007 to present
	Executive Vice President, Global Human Capital, TeleTech	March 21, 2006 to April 13, 2007
	Senior Vice President, Human Capital, TeleTech Holdings, Inc.	July 13, 2001 to March 20, 2006
Geisha J. Williams	Senior Vice President, Energy Delivery	December 1, 2007 to present
	Vice President, Power Systems, Distribution, Florida Power and Light Company	July 2003 to July 2007
	Vice President, Distribution Operations, Florida Power and Light Company	February 2002 to July 2003
G. Robert Powell	Vice President, Chief Financial Officer, and Controller	June 1, 2007 to present
	Vice President and Controller	December 21, 2005 to May 31, 2007
	Controller (Interim)	November 9, 2005 to December 20, 2005
	Vice President and Controller, PG&E Corporation	October 4, 2005 to present
	Partner, PricewaterhouseCoopers LLP	July 2002 to September 2005
Fong Wan	Vice President, Energy Procurement	January 9, 2006 to present
	Vice President, Power Contracts and Electric Resource Development	May 1, 2004 to January 8, 2006
	Vice President, Risk Initiatives, PG&E Corporation Support Services, Inc.	November 1, 2000 to April 30, 2004

PART II

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

As of February 19, 2008, there were 88,752 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 2007 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. The discussion of dividends with respect to PG&E Corporation's common stock set forth under the heading “Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Financial Resources—Dividends” in the 2007 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

PG&E Corporation did not repurchase any shares of its common stock during 2007. The Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding during of 2007.

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 2007 Annual Report, which information is hereby incorporated by reference and filed as part of 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 2007 Annual Report, which discussion is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Information responding to Item 7A appears in the 2007 Annual Report under the heading “Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Management Activities,” and under Notes 2 and 12 of the “Notes to the Consolidated Financial Statements” of the 2007 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 8. *Financial Statements and Supplementary Data*

Information responding to Item 8 appears in the 2007 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 hereby incorporated by reference and filed as part of 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, 2007, 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, 2007 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 2007 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 hereby incorporated by reference and filed as part of Exhibit 13 to this

report.

Item 9B. Other Information

Amendment to Bylaws

On February 20, 2008, the Boards of Directors of PG&E Corporation and the Utility amended the respective company's Bylaws to decrease the authorized number of directors, effective May 14, 2008, to eliminate the vacancy on the Board of Directors that will result from the retirement of David A. Coulter as a director of each company following the companies' joint annual meeting of shareholders. Under PG&E Corporation's Bylaws, the authorized number of directors may not be less than 7 or more than 13, but within that range the Board of Directors may set the exact number of directors by an amendment to the Bylaws. Under the Utility's Bylaws, the authorized number of directors may not be less than 9 or more than 17, but within that range the Board of Directors may set the exact number of directors by an amendment to the Bylaws. Effective May 14, 2008, PG&E Corporation's authorized number of directors will decrease from 10 to 9 and the Utility's authorized number of directors will decrease from 11 to 10. The text of the amendment to PG&E Corporation's Bylaws is attached to this report as Exhibit 3.4 and the text of the amendment to the Utility's Bylaws is attached to this report as Exhibit 3.7.

Under PG&E Corporation's and the Utility's Corporate Governance Guidelines, at least 75% of its Board is required to be composed of independent directors, generally defined as directors who (1) are neither current nor former officers or employees of, nor consultants to, PG&E Corporation, the Utility, or their consolidated subsidiaries, (2) are neither current nor former officers or employees of any other corporation on whose board of directors any officer of the Utility serves as a member, and (3) otherwise meet the definition of "independence" set forth in the stock exchange rules applicable to PG&E Corporation and the Utility. The composition of PG&E Corporation's and the Utility's Board of Directors currently meets the Corporate Governance Guidelines and will continue to do so after May 14, 2008.

2008 Officer Compensation

On February 20, 2008, the Compensation Committee of the PG&E Corporation Board of Directors ("Committee") approved the specific performance targets for each component of the 2008 Short-Term Incentive Plan ("STIP"). The Committee previously approved the STIP structure and the weighting of each component in December 2007. 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 2008 performance targets are met. The Committee will continue to retain full discretion as to the determination of final officer STIP payments.

The 2008 STIP structure for officers focuses the annual incentive opportunity on returns to shareholders by emphasizing financial objectives such as earnings from operations. The structure also recognizes the equal importance of improving reliability and customer satisfaction, and employee safety and engagement. Corporate financial performance, as measured by corporate earnings from operations, will account for 40% of the incentive, 20% of the incentive will be based on the Utility's success in improving reliability, 20% of the incentive will be based on the Utility's success in improving customer satisfaction, 10% will be based on the results of an employee opinion survey, and the remaining 10% will be based on achieving safety standards. For 2008, the Committee has adopted a mechanism stating that if corporate financial performance does not exceed 98% of the budgeted earnings from operations, the aggregate operational metric contribution to the 2008 STIP pool will be capped at 100% of the operational component target award, or 60% of the total target STIP award pool.

The corporate financial performance measure 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 2008 performance targets for each of the four other measures set forth in the table below. The 2007 performance results for each of these measures are included for comparative purposes.

2008 STIP Operational Performance Targets ⁽¹⁾

Measure	Relative Weight	2007 Results	2008 Target
Customer Satisfaction and Brand Health Index (Residential & Business) (2)	20%	76.00	77.00
Reliable Energy Delivery Index(3)	20%	1.17	1.0
Employee Survey (Premier) Index(4)	10%	64.3%	66.0%
Occupational Safety and Health Administration (OSHA) Recordable Injury Rate(5)	10%	4.097	3.483

1. As explained above, 40% of the STIP award will be based on achievement of corporate earnings from operations targets.
2. 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. This index replaces the index used in the 2006 and 2007 STIP structures based on residential and business customer satisfaction indices as reported the J.D. Power Residential Customer Satisfaction Survey and the J.D. Power Business Customer Satisfaction Survey.
3. The Reliable Energy Delivery Index is a composite index score that measures key drivers of reliability, including outage frequency and duration (System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI)), Execution of Electric-Based Work Units, and Gas Transmission and Distribution Integrity. This index replaces the Business Transformation Index used in the 2007 STIP structure.
4. 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.
5. 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 Corporation's OSHA Recordable rate from the prior year and is used to monitor the effectiveness of the Corporation's 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 base salary, as determined by the Committee.

Non-Employee Director Compensation

Also on February 20, 2008, the Boards of Directors of PG&E Corporation and the Utility amended each company's resolution regarding non-employee director compensation to clarify and restate the application of the compensation program for non-employee directors in light of (1) the division of the PG&E Corporation Nominating, Compensation, and Governance Committee into two separate committees (the Nominating and Governance Committee and the Compensation Committee), and (2) recent changes to the process for selecting the lead director. The amended resolutions do not change the compensation levels previously authorized by the Boards of Directors on December 20, 2006. The amended resolutions are effective as of January 1, 2008 and are attached to this report as exhibits.

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 2008 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 2007 there were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement relating to the 2007 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 2008 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 - 2007," "Grants of Plan-based Awards in 2007," "Outstanding Equity Awards at Fiscal Year End - 2007," "Option Exercises and Stock Vested During 2007," "Pension Benefits," "Non-Qualified Deferred Compensation," "Compensation of Directors," and "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" in the Joint Proxy Statement relating to the 2008 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder 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 2008 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2007 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	3,970,661 ⁽¹⁾	\$24.00	10,847,999 ⁽²⁾
Equity compensation plans not approved by shareholders	—	\$—	—
Total equity compensation plans	3,970,661 ⁽¹⁾	\$24.00	10,847,999 ⁽²⁾

(1) Includes 87,989 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, 2007. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock and phantom stock payable in an equal number of shares upon termination of employment or service as a director. 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 payable in an equal number of shares upon termination of employment or service as a director. For a description of the LTIP and the 2006 LTIP, see Note 14 of the Notes to the Consolidated Financial Statements in the 2007 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 2008 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 2008 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 2007 Annual Report and are incorporated by reference in this report:

Consolidated Statements of Income for the Years Ended December 31, 2007, 2006, and 2005 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2007 and 2006 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2006, and 2005 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2007, 2006, and 2005 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, 2007 and 2006 and for the Years Ended December 31, 2007, 2006, and 2005.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2007, 2006, and 2005.

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 September 19, 2007 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007) (File No. 1-12609), Exhibit 3.1)
3.4	Text of the amendment to the Bylaws of PG&E Corporation effective May 14, 2008
3.5	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)
3.6	Bylaws of Pacific Gas and Electric Company amended as of January 1, 2008
3.7	Text of the amendment to the Bylaws of Pacific Gas and Electric Company effective May 14, 2008
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	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).
4.5	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 Supplemental Retirement Savings Plan effective as of 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 10.11)
- *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 Retention Agreement between PG&E Corporation and Thomas B. King dated August 31, 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 10.2)
- *10.11 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)
- *10.12 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)
- *10.13 Performance Share Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007
- *10.14 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007
- *10.15 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)
- *10.16 Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006) (File No. 1-12609), Exhibit 10.18)

- *10.17 Letter regarding Compensation Agreement between PG&E Corporation and G. Robert Powell dated August 8, 2005
- *10.18 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of 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 10.17)
- *10.19 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2008
- *10.20 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.20)
- *10.21 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005 (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 10.20)
- *10.22 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-2348), Exhibit 10.27)
- *10.23 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)
- *10.24 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)
- *10.25 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)
- *10.26 Resolution of the PG&E Corporation Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007 (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, 2006 (File No. 1-12609 and File No. 12348), Exhibit 10.29)
- *10.27 Resolution of the Pacific Gas and Electric Company Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007 (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, 2006 (File No. 1-12609 and File No. 12348), Exhibit 10.30)
- *10.28 Resolution of the PG&E Corporation Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008
- *10.29 Resolution of the Pacific Gas and Electric Company Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008
- *10.30 PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 (with respect to change in control provisions) and December 20, 2006 and October 17, 2007 (with respect to Section 7 governing nondiscretionary awards to non-employee directors)
- *10.31 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)
- *10.32 Form of Restricted Stock Award Agreement for 2003 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, 2002 (File No. 1-12609), Exhibit 10.46)

- *10.33 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)
- *10.34 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)
- *10.35 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)
- *10.36 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)
- *10.37 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)
- *10.38 Form of Performance Share Award Agreement for 2004 grants 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 10.38)
- *10.39 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)
- *10.40 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)
- *10.41 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)
- *10.42 PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (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 10.2)
- *10.43 PG&E Corporation Executive Stock Ownership Program Guidelines as amended 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 10.46)
- *10.44 PG&E Corporation Officer Severance Policy, as amended effective as of 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 10.37) (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)
- *10.45 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)
- *10.46 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)
- *10.47 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)
- *10.48 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)

- *10.49 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)
- *10.50 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 2007 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," and "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," "Report of Independent Registered Public Accounting Firm," 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, 2007 to be signed on their behalf by the undersigned, thereunto duly authorized.

PG&E CORPORATION
(Registrant)

PACIFIC GAS AND ELECTRIC COMPANY
(Registrant)

*PETER A. DARBEE

*WILLIAM T. MORROW

By: Peter A. Darbee
Chairman of the Board, Chief Executive Officer
and President

By: William T. Morrow
President and Chief Executive Officer

Date: February 22, 2008

Date: February 22, 2008

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		
*PETER A. DARBEE Peter A. Darbee	Chairman of the Board, Chief Executive Officer, President and Director (PG&E Corporation)	February 22, 2008
*WILLIAM T. MORROW William T. Morrow	President and Chief Executive Officer (Pacific Gas and Electric Company)	February 22, 2008
B. Principal Financial Officers		
*CHRISTOPHER P. JOHNS Christopher P. Johns	Senior Vice President, Chief Financial Officer and Treasurer (PG&E Corporation)	February 22, 2008
*G. ROBERT POWELL G. Robert Powell	Vice President, Chief Financial Officer and Controller (Pacific Gas and Electric Company)	February 22, 2008
C. Principal Accounting Officer		
*G. ROBERT POWELL G. Robert Powell	Vice President and Controller (PG&E Corporation and (Pacific Gas and Electric Company)	February 22, 2008 February 22, 2008
D. Directors		
*DAVID R. ANDREWS David R. Andrews	Director	February 22, 2008
*LESLIE S. BILLER Leslie S. Biller	Director	February 22, 2008
*DAVID A. COULTER David A. Coulter	Director	February 22, 2008
*C. LEE COX C. Lee Cox	Director	February 22, 2008
*MARYELLEN C. HERRINGER Maryellen C. Herringer	Director	February 22, 2008
*RICHARD A. MESERVE Richard A. Meserve	Director	February 22, 2008

<u>*MARY S. METZ</u> Mary S. Metz	Director	February 22, 2008
<u>*WILLIAM T. MORROW</u> William T. Morrow	Director (Pacific Gas and Electric Company only)	February 22, 2008
<u>*BARBARA L. RAMBO</u> Barbara L. Rambo	Director	February 22, 2008
<u>*BARRY LAWSON WILLIAMS</u> Barry Lawson Williams	Director	February 22, 2008
*By: <u>HYUN PARK</u> HYUN PARK, Attorney-in-Fact		

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

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, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and the Company's and Utility's internal control over financial reporting as of December 31, 2007, and have issued our reports thereon dated February 21, 2008; such consolidated financial statements and reports are included in your 2007 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

San Francisco, California
February 21, 2008

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

	Balance at December 31,	
	2007	2006
ASSETS		
Current Assets:		
Cash and cash equivalents	\$ 204	\$ 386
Advances to affiliates	30	42
Income taxes receivable	46	-
Other current assets	3	3
Total current assets	283	431
Equipment	17	15
Accumulated depreciation	(15)	(14)
Net equipment	2	1
Investments in subsidiaries	8,886	7,959
Other investments	87	81
Deferred income taxes	51	132
Other	9	10
Total Assets	\$ 9,318	\$ 8,614
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable		
Related parties	\$ 40	\$ 41
Other	24	18
Long-term debt, classified as current	-	280
Income taxes payable	-	122
Other	174	210
Total current liabilities	238	671
Noncurrent Liabilities:		
Long-term debt	280	-
Income taxes payable	131	-
Other	116	133
Total noncurrent liabilities	527	133
Common Shareholders' Equity		
Common stock	6,110	5,877
Common stock held by subsidiary	(718)	(718)
Reinvested earnings	3,151	2,670
Accumulated other comprehensive income (loss)	10	(19)
Total common shareholders' equity	8,553	7,810
Total Liabilities and Shareholders' Equity	\$ 9,318	\$ 8,614

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

	Year Ended December 31,		
	2007	2006	2005
Administrative service revenue	\$ 102	\$ 110	\$ 97
Equity in earnings of subsidiaries	1,006	964	918
Operating expenses	(112)	(115)	(97)
Interest income	15	15	9
Interest expense	(31)	(30)	(35)
Other expense	(6)	(1)	(17)
Income before income taxes	974	943	875
Income tax benefit	32	48	29
Income from continuing operations	1,006	991	904
Gain on disposal of NEGТ	--	--	13
Net income before intercompany eliminations	\$ 1,006	\$ 991	\$ 917
Weighted average common shares outstanding, basic	351	346	372
Weighted average common shares outstanding, diluted	353	349	378
Earnings per common share, basic(1)	\$ 2.79	\$ 2.78	\$ 2.40
Earnings per common share, diluted(1)	\$ 2.78	\$ 2.76	\$ 2.37

(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, 2007 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 STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2007	2006	2005
Cash Flows from Operating Activities:			
Net income	\$ 1,006	\$ 991	\$ 917
Gain on disposal of NEGT (net of income tax benefit of \$13 million in 2005)	--	--	(13)
Net income from continuing operations	1,006	991	904
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	1	--	--
Equity in earnings of subsidiaries	(1,006)	(964)	(918)
Deferred taxes	47	2	(23)
Other	(24)	130	86
Net cash provided by operating activities	24	159	49
Cash Flows From Investing Activities:			
Capital expenditures	(1)	(1)	(1)
Investment in subsidiaries	(405)	--	--
Stock repurchase by subsidiary	--	--	1,910
Dividends received from subsidiaries	509	460	445
Other	--	--	(38)
Net cash provided by investing activities	103	459	2,316
Cash Flows From Financing Activities ⁽²⁾ :			
Common stock issued	175	131	243
Common stock repurchased	--	(114)	(2,188)
Common stock dividends paid	(496)	(456)	(334)
Long-term debt redeemed	--	--	(2)
Other	12	(43)	(17)
Net cash used by financing activities	(309)	(482)	(2,298)
Net change in cash and cash equivalents	(182)	136	67
Cash and cash equivalents at January 1	386	250	183
Cash and cash equivalents at December 31	\$ 204	\$ 386	\$ 250

(2) 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 2006, 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.

On April 15, July 15 and October 17, 2005, PG&E Corporation paid a quarterly common stock dividend of \$0.30 per share, totaling approximately \$356 million. Of the total dividend payments made by PG&E Corporation in 2005, approximately \$22 million was paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation. PG&E Corporation did not pay any dividends during 2004.

PG&E Corporation

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2007, 2006, and 2005

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:					
2007:					
Allowance for uncollectible accounts(1)(2)	\$ 50	\$ 20	\$ -	\$ 12	\$ 58
2006:					
Allowance for uncollectible accounts(1)(2)	\$ 77	\$ 2	\$ -	\$ 29	\$ 50
2005:					
Allowance for uncollectible accounts(1)(2)	\$ 93	\$ 21	\$ -	\$ 37	\$ 77

(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, 2007, 2006, and 2005

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:					
2007:					
Allowance for uncollectible accounts(1)	\$ 50	\$ 20	\$ -	\$ 12	\$ 58
2006:					
Allowance for uncollectible accounts(1)	\$ 77	\$ 2	\$ -	\$ 29	\$ 50
2005:					
Allowance for uncollectible accounts(1)	\$ 93	\$ 21	\$ -	\$ 37	\$ 77

(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 September 19, 2007 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007) (File No. 1-12609), Exhibit 3.1)
3.4	Text of the amendment to the Bylaws of PG&E Corporation effective May 14, 2008
3.5	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)
3.6	Bylaws of Pacific Gas and Electric Company amended as of January 1, 2008
3.7	Text of the amendment to the Bylaws of Pacific Gas and Electric Company effective May 14, 2008
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	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).
4.5	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 Supplemental Retirement Savings Plan effective as of 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 10.11)
- *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 Retention Agreement between PG&E Corporation and Thomas B. King dated August 31, 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 10.2)
- *10.11 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)
- *10.12 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)
- *10.13 Performance Share Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007
- *10.14 Restricted Stock Award Agreement between PG&E Corporation and William T. Morrow dated November 6, 2007
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- *10.15 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)
 - *10.16 Letter regarding Compensation Arrangement between PG&E Corporation and Hyun Park dated October 10, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2006) (File No. 1-12609), Exhibit 10.18)
 - *10.17 Letter regarding Compensation Agreement between PG&E Corporation and G. Robert Powell dated August 8, 2005
 - *10.18 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of 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 10.17)
 - *10.19 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2008
 - *10.20 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2007 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.20)
 - *10.21 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005 (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 10.20)
 - *10.22 Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of January 1, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005) (File No. 1-2348), Exhibit 10.27)
 - *10.23 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)
 - *10.24 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)
 - *10.25 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)
 - *10.26 Resolution of the PG&E Corporation Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007 (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, 2006 (File No. 1-12609 and File No. 12348), Exhibit 10.29)
 - *10.27 Resolution of the Pacific Gas and Electric Company Board of Directors dated December 20, 2006, adopting director compensation arrangement effective January 1, 2007 (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, 2006 (File No. 1-12609 and File No. 12348), Exhibit 10.30)
 - *10.28 Resolution of the PG&E Corporation Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008
 - *10.29 Resolution of the Pacific Gas and Electric Company Board of Directors dated February 20, 2008, adopting director compensation arrangement effective January 1, 2008
 - *10.30 PG&E Corporation 2006 Long-Term Incentive Plan, as amended on February 15, 2006 (with respect to change in control provisions) and December 20, 2006 and October 17, 2007 (with respect to Section 7 governing nondiscretionary awards to non-employee directors)
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- *10.31 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)
 - *10.32 Form of Restricted Stock Award Agreement for 2003 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, 2002 (File No. 1-12609), Exhibit 10.46)
 - *10.33 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)
 - *10.34 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)
 - *10.35 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)
 - *10.36 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)
 - *10.37 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)
 - *10.38 Form of Performance Share Award Agreement for 2004 grants 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 10.38)
 - *10.39 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)
 - *10.40 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)
 - *10.41 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)
 - *10.42 PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (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 10.2)
 - *10.43 PG&E Corporation Executive Stock Ownership Program Guidelines as amended 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 10.46)
 - *10.44 PG&E Corporation Officer Severance Policy, as amended effective as of 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 10.37)
 - *10.45 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)
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*10.46	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)
*10.47	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)
*10.48	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)
*10.49	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)
*10.50	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 2007 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," and "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," "Report of Independent Registered Public Accounting Firm," 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

Amendment to PG&E Corporation Bylaws

Effective May 14, 2008

**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 nine (9) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

Bylaws
of
Pacific Gas and Electric Company
amended as of January 1, 2008

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 eleven (11) 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.

Amendment to Pacific Gas and Electric Company Bylaws

Effective May 14, 2008

**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.

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

PERFORMANCE SHARE GRANT

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

Date of Grant: November 6, 2007

Name of Recipient: MORROW, WILLIAM T.

Last Four Digits of Recipient's Social Security Number: --8024

Number of Shares of Restricted Stock Granted: 22,480

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 are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Performance Shares dated January 1, 2007.

Recipient: /s/ William T. Morrow
(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 (“LTIP”)

PERFORMANCE SHARE AGREEMENT

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 2011. 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%

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.

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 following the date that the Nominating, Compensation, and Governance 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.

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, you shall also 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 completion of the Performance Period based on the same formula applied to active employees. You shall also receive a cash payment, if any, equal to the

A-2

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. You 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 completion of the Performance Period based on the same formula applied to active employees. You 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.
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 completion of the Performance Period based on the same formula applied to active employees. You shall also 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

A-3

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. 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.

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 on the first business day of the year following the Change in Control. The payment, if any, will be based on PG&E Corporation’s TSR for the period from January 1, 2008 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. 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.

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, on the first business day of the

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.

A-4

following year following the completion of the Performance Period and will be based on the same formula applied to active employees. You shall also 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.

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

RESTRICTED STOCK GRANT

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

Date of Grant: November 6, 2007

Name of Recipient: MORROW, WILLIAM T.

Last Four Digits of Recipient's Social Security Number: --8024

Number of Shares of Restricted Stock Granted: 22,480

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 are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock dated January 1, 2007.

Recipient: /s/ William T. Morrow
(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 (“LTIP”)

RESTRICTED STOCK AGREEMENT

The LTIP and Other Agreements	This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock, 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 Restricted Stock	PG&E Corporation grants you the number of shares of Restricted Stock shown on the cover sheet of this Agreement. The shares of Restricted Stock are subject to the terms and conditions of this Agreement and the LTIP.
Lapse of Restrictions	As long as you remain employed with PG&E Corporation, the restrictions will lapse as to 20 percent of the total number of shares of Restricted Stock originally subject to this Agreement, as shown above on the cover sheet, on the first business day of January of each of 2009, 2010, and 2011. The restrictions will lapse as to an additional 40 percent of the total number of shares of Restricted Stock on the first business day of January of 2013; provided, however, that the restrictions will lapse as to this 40 percent on the first business day of January of 2011 if PG&E Corporation’s performance in total shareholder return (“TSR”) is at or above the 75th percentile for the prior three calendar years as compared with the comparator group established from time to time by PG&E Corporation. (Each lapse day is an “Annual Lapse Date”). Except as described below, all shares of Restricted Stock subject to this Agreement as to which the restrictions have not lapsed shall be forfeited upon termination of your employment. To the extent this Agreement provides for the continued lapse of restrictions following the termination of employment, such continued lapse shall be subject to your continued compliance with certain post-employment restrictions.
Voluntary Termination	In the event that you terminate your employment with PG&E Corporation voluntarily, you will automatically forfeit to PG&E Corporation all of the shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such Termination.
Termination for Cause	If your employment with PG&E Corporation is terminated by PG&E Corporation for cause, you will automatically forfeit to PG&E Corporation all shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such termination. In general,

A-1

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 restrictions on your Restricted Stock lapse, and you are an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed during the period of the “Severance Multiple” under the applicable severance policy shall continue to lapse pursuant to the regular lapse schedule (or sooner, to the extent described below in connection with a Change in Control during such period). In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed within 12 months following such termination will continue to lapse pursuant to the regular lapse schedule (or sooner, in the event of a Change in Control during such period). All other outstanding shares of Restricted Stock shall automatically be forfeited to PG&E Corporation upon such termination.
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Retirement

In the event of your Retirement, the restrictions on your outstanding shares of Restricted Stock will continue to lapse as though your employment had continued. 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, the restrictions on all of your shares of Restricted Stock shall lapse on the next Annual Lapse Date. In the event of a Change in Control after such termination and before such next Annual Lapse Date, the restrictions as to all shares of Restricted Stock shall immediately lapse to the extent described below under “Change in Control.”

**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 restrictions on all shares of Restricted Stock shall lapse on the next Annual Lapse Date. In the event of a Change in Control after such Termination and before such next Annual Lapse Date, the restrictions as to all shares of Restricted Stock shall immediately lapse to the extent described below under “Change in Control.”

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

A-2

may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide substantially equivalent awards associated with the Acquiror’s stock. If this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award, the restrictions on all of your outstanding shares of Restricted Stock shall automatically lapse and the shares shall become nonforfeitable immediately preceding, and contingent on, the Change in Control of PG&E Corporation.

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 2008 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 end of the calendar year preceding the third Annual Lapse Date.

**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, the restrictions on all of your outstanding shares of Restricted Stock (to the extent the restrictions did not previously lapse upon failure of the Acquiror to assume or continue this Award) shall lapse and the shares shall become nonforfeitable on the date of termination of your employment. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Escrow

The certificates for the Restricted Stock shall be deposited in escrow with the Corporate Secretary of PG&E Corporation to be held in accordance with the provisions of this paragraph. Each deposited certificate shall be accompanied by any assignment documents PG&E Corporation may require you to execute. The deposited certificates shall remain in escrow until such time as the certificates are to be released or otherwise surrendered for cancellation as discussed below.

All dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

Release of Shares and Withholding Taxes

The shares of Restricted Stock held in escrow hereunder shall be subject to the following terms and conditions relating to their release from escrow or their surrender to PG&E Corporation:

- When the restrictions as to your shares of Restricted Stock lapse as described above, the certificates for such shares shall be released from escrow and delivered to you, at your request within thirty (30) days of the applicable Annual Lapse Date.
- Upon termination of your employment, any shares of Restricted Stock as to which the restrictions have not lapsed shall be forfeited and

A-3

automatically surrendered to PG&E Corporation as provided herein.

Note that you must make arrangements acceptable to PG&E Corporation to satisfy withholding or other taxes that may be due before your shares will be released to you. If you so elect, PG&E Corporation will assist you in selling your shares through a broker so that you can use the sales proceeds to satisfy applicable taxes. You will receive the remaining proceeds in cash. However, if you wish to receive the stock certificates in lieu of selling your shares, you will need to make arrangements to pay the applicable taxes either by check or through payroll deduction. PG&E Corporation will notify you about how to instruct PG&E Corporation to sell your shares when the restrictions lapse or make other arrangements.

Code Section 83(b) Election

Under Section 83(a) of the Code, the Fair Market Value of the Restricted Stock on the date any forfeiture restrictions applicable to such Restricted Stock lapse will be reportable as ordinary income at that time. For this purpose, “forfeiture restrictions” include surrender to PG&E Corporation of Restricted Stock as described above. You may elect to be taxed at the time the Restricted Stock is granted to you, rather than when the restrictions lapse by filing an election under Section 83(b) of the Code with the Internal Revenue Service within thirty (30) days after the Date of Grant. Failure to make this filing within the thirty (30) day period will result in the recognition of ordinary income by you (in the event the Fair Market Value of the Restricted Stock increases after the date of purchase) as the forfeiture restrictions lapse. **YOU ACKNOWLEDGE THAT IT IS YOUR SOLE RESPONSIBILITY, AND NOT PG&E CORPORATION’S, TO FILE A TIMELY ELECTION UNDER CODE SECTION 83(b). YOU ARE RELYING SOLELY ON YOUR OWN ADVISORS WITH RESPECT TO THE DECISION AS TO WHETHER OR NOT TO FILE A CODE SECTION 83(b) ELECTION.**

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.

Voting and Other Rights

Subject to the terms of this Agreement, you shall have all the rights and privileges of a shareholder of PG&E Corporation while the Restricted Stock is held in escrow, including the right to vote. As described above, all dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

A-4

Restrictions on Issuance

PG&E Corporation will not issue any Restricted Stock if the issuance of such Restricted Stock at that time would violate any law or regulation.

**Restrictions on Resale
and Hedge Transactions**

By signing this Agreement, you agree not to sell any Restricted Stock before the restrictions lapse or sell any shares acquired under this grant at a time when applicable laws, regulations or Company or underwriter trading policies prohibit sale. In particular, in connection with any underwritten public offering by PG&E Corporation of its equity securities pursuant to an effective registration statement filed under the Securities Act of 1933, you shall not sell, make any short sale of, loan, hypothecate, pledge, grant any option for the purchase of, or otherwise dispose or transfer for value or agree to engage in any of the foregoing transactions with respect to any shares acquired under this grant without the prior written consent of PG&E Corporation or its underwriters, for such period of time after the effective date of such registration statement as may be requested by PG&E Corporation or the underwriters.

If the sale of shares acquired under this grant is not registered under the Securities Act of 1933, but an exemption is available which requires an investment or other representation and warranty, you shall represent and agree that the Shares being acquired are being acquired for investment, and not with a view to the sale or distribution thereof, and shall make such other representations and warranties as are deemed necessary or appropriate by PG&E Corporation and its counsel.

By your acceptance of the grant, you agree that while the Restricted Stock is subject to restrictions, you will not enter into a corresponding hedging transaction relating to PG&E Corporation’s stock nor engage in any short sale of PG&E Corporation’s stock. This prohibition shall not apply to transactions effected through PG&E Corporation’s benefit plans that provide an opportunity to invest in Company stock or which provide compensation based on the price of Company stock.

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.

Legends

All certificates that may be issued to represent the Restricted Stock issued under this grant shall, where applicable, have endorsed thereon the following legends:

“THE SHARES REPRESENTED BY THIS CERTIFICATE ARE SUBJECT TO CERTAIN RESTRICTIONS ON TRANSFER SET FORTH IN AN AGREEMENT BETWEEN PG&E CORPORATION AND THE REGISTERED HOLDER, OR HIS OR HER PREDECESSOR IN INTEREST. A COPY OF SUCH AGREEMENT IS ON FILE AT THE PRINCIPAL OFFICE OF PG&E CORPORATION AND WILL BE FURNISHED UPON WRITTEN REQUEST TO THE CORPORATE SECRETARY OF PG&E CORPORATION BY THE HOLDER OF

A-5

RECORD OF THE SHARES REPRESENTED BY THIS CERTIFICATE.”

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.



Christopher P. Johns
Senior Vice President and
Chief Financial Officer

One Market, Spear Tower
Suite 2400
San Francisco, CA
415.267.7036
Fax: 415.267.7263

August 8, 2005

Mr. G. Robert Powell
335 Crosstree Lane
Atlanta, GA 30328

Dear Bob:

On behalf of PG&E Corporation, I am pleased to extend an invitation to you to join our organization as Vice President and Controller, reporting to me.

Your initial total compensation package will consist of the following:

1. An annual base salary of \$280,000 (\$23,333.33/month) subject to possible increases through our annual salary review plan.
 2. A one-time bonus of \$225,000 payable within 60 days of your date of hire, subject to normal payroll withholdings. Should you leave the company or should your employment terminate 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 \$126,000 that equals 45% of your base salary in an annual short-term incentive plan under which your actual incentive dollars may range from zero to \$252,000 based on performance relative to established goals. For 2005, this incentive will be prorated for the number of months worked from your date of hire and will be payable in 2006.
 4. Participation in the PG&E Corporation Long-Term Incentive Program (LTIP) as a band 4 officer. Grants under the LTIP are split into thirds and delivered through three separate vehicles: stock options, restricted stock and performance shares; and are generally made annually on the first business day of the year. Your initial LTIP grant will be made in January 2006 and will have an estimated current value of \$200,000. This estimated current value is used only for the purpose of determining the number of shares or units for your grant. The ultimate value that you realize will depend upon your employment status and the performance of PG&E Corporation common stock.
 5. 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 an after-tax basis. We will make a basic contribution to your account equal to 5% of your salary. Additionally, we will match, dollar-for-dollar, any contribution you make up to 5% of your salary after you have completed one year of service. All of the above contributions are subject to applicable legal limits.
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Mr. Powell
August 8, 2005
Page 2

6. 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 and basic contributions that cannot be provided through the RSP, due to legal limitations imposed on highly compensated employees. Additionally, we will make a basic contribution to your account equal to 5% of any amounts paid from the annual short-term incentive plan referenced in item 3 above.
 7. 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.
 8. PG&E Corporation also offers employees an initial allocation of Paid Time Off (PTO) upon hire; this initial allocation may be up to 160 hours based on start date. Future allocations of PTO are made each year on January 1 and are based on your start date and amount worked in the preceding year. For example, by starting work in September and working full-time for the remainder of 2005, you will be eligible for 80 hours of PTO upon hire and 54 hours on January 1, 2006. Beginning January 1, 2007, you will be eligible for 160 hours of PTO, provided that you work full-time for all of 2006. In addition, PG&E Corporation recognizes 10 paid company holidays annually and provides 3 floating holidays immediately upon hire and at the beginning of each year.
 9. An annual perquisite allowance of \$15,000 to be used in lieu of individual authorizations for cars and memberships in clubs and civic organizations. For 2005, you will receive 50% of this amount (\$7,500), since your date of hire will be after June 30.
 10. A comprehensive executive relocation assistance package, including: Reimbursement of closing costs on the sale of your current residence, contingent on using the PG&E designated relocation company and on the purchase of a new residence; the move of your household goods, 60 days of storage and delivery of the goods out of storage; and a lump sum payment of \$10,000 payable within 60 days of your date of hire. In addition, the package will include financial assistance in the form of a monthly mortgage subsidy of \$3,000 (interest only) for a period of 48 months. This subsidy is contingent upon the following: (a) your purchase of a principal residence (within 50 miles of your work location) within one year of your date of hire, (b) your satisfying typical mortgage qualification criteria, and (c) use of a company-designated lender. Should you have any questions regarding the relocation package, please contact Denise Nicco, Director of Relocation at (415) 817-8230.
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Mr. Powell
August 8, 2005
Page 3

As we have discussed, this offer is contingent upon your passing comprehensive background verification, including a credit check, 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 PG&E Corporation and elements of your compensation are subject to approval by the Board of Directors of PG&E Corporation. Should you accept our offer, we will provide you with additional details on meeting these requirements.

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 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 questions.

Sincerely,

/s/ Christopher P. Johns

CHRISTOPHER P. JOHNS
Senior Vice President, Chief Financial Officer and Controller

Attachment

This is to confirm my acceptance of PG&E Corporation's offer as the Vice President and Controller outlined above.

/s/ G. Robert Powell 8/9/05
(Signature and Date)

2008 OFFICER SHORT-TERM INCENTIVE PLAN

On February 20, 2008, the Compensation Committee of the PG&E Corporation Board of Directors (“Committee”) approved the specific performance targets for each component of the 2008 Short-Term Incentive Plan (“STIP”). The Committee previously approved the STIP structure and the weighting of each component in December 2007. 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 2008 performance targets are met. The Committee will continue to retain full discretion as to the determination of final officer STIP payments.

The 2008 STIP structure for officers focuses the annual incentive opportunity on returns to shareholders by emphasizing financial objectives such as earnings from operations. The structure also recognizes the equal importance of improving reliability and customer satisfaction, and employee safety and engagement. Corporate financial performance, as measured by corporate earnings from operations, will account for 40% of the incentive, 20% of the incentive will be based on the Utility’s success in improving reliability, 20% of the incentive will be based on the Utility’s success in improving customer satisfaction, 10% will be based on the results of an employee opinion survey, and the remaining 10% will be based on achieving safety standards. For 2008, the Committee has adopted a mechanism stating that if corporate financial performance does not exceed 98% of the budgeted earnings from operations, the aggregate operational metric contribution to the 2008 STIP pool will be capped at 100% of the operational component target award, or 60% of the total target STIP award pool.

The corporate financial performance measure 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 2008 performance targets for each of the four other measures set forth in the table below. The 2007 performance results for each of these measures are included for comparative purposes.

2008 STIP Operational Performance Targets ⁽¹⁾

Measure	Relative Weight	2007 Results	2008 Target
Customer Satisfaction and Brand Health Index (Residential & Business)(2)	20%	76.00	77.00
Reliable Energy Delivery Index(3)	20%	1.17	1.0
Employee Survey (Premier) Index(4)	10%	64.3%	66.0%
Occupational Safety and Health Administration (OSHA) Recordable Injury Rate(5)	10%	4.097	3.483

1. As explained above, 40% of the STIP award will be based on achievement of corporate earnings from operations targets.
2. 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. This index replaces the index used in the 2006 and 2007 STIP structures based on residential and business customer satisfaction indices as reported the J.D. Power Residential Customer Satisfaction Survey and the J.D. Power Business Customer Satisfaction Survey.
3. The Reliable Energy Delivery Index is a composite index score that measures key drivers of reliability, including outage frequency and duration (System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI)), Execution of Electric-Based Work Units, and Gas Transmission and Distribution Integrity. This index replaces the Business Transformation Index used in the 2007 STIP structure.
4. 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.
5. 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 Corporation's OSHA Recordable rate from the prior year and is used to monitor the effectiveness of the Corporation's 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 base salary, as determined by the Committee.

Director Compensation

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION

February 20, 2008

WHEREAS, the Board of Directors has previously approved a compensation program for the non-employee directors of this corporation; and

WHEREAS, the Board of Directors desires to clarify and restate the application of the compensation program for non-employee directors, in light of (1) the division of the PG&E Corporation Nominating, Compensation, and Governance Committee into two separate committees – a Compensation Committee and a Nominating and Governance Committee – effective January 1, 2008, and (2) changes to the process by which the Board of Directors selects its lead director, effective January 1, 2008;

NOW, THEREFORE, BE IT RESOLVED that, effective as of January 1, 2007, directors who are not employees of this corporation or Pacific Gas and Electric Company (“non-employee directors”) shall be paid a retainer of \$12,500 per calendar quarter, which shall be in addition to fees paid for attendance at Board and Board committee meetings; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2007, 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 as of January 1, 2008, 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 for any calendar quarter during which such director also serves as lead director; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2007, non-employee directors shall be paid a fee of \$1,750 for each meeting of the Board and for 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 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 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 of Directors 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 attending Board or committee meetings; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2008, the resolution on this subject adopted by the Board of Directors on December 20, 2006 is hereby superseded.

Director Compensation

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY

February 20, 2008

WHEREAS, the Board of Directors has previously approved a compensation program for the non-employee directors of this company; and

WHEREAS, the Board of Directors desires to clarify and restate the application of the compensation program for non-employee directors, in order to conform it to the program for non-employee directors of PG&E Corporation;

NOW, THEREFORE, BE IT RESOLVED that, effective as of January 1, 2007, directors who are not employees of this company or PG&E Corporation ("non-employee directors") shall be paid a retainer of \$12,500 per calendar quarter which shall be in addition to any fees paid for attendance at Board and Board committee 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 director or advisory director of PG&E Corporation; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2007, 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 as of January 1, 2007, 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 (1) 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 (2) a non-employee

director duly appointed to chair a permanent committee of this Board shall not be paid an additional retainer for any calendar quarter during which such director also serves as lead director; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2007, non-employee directors attending any meeting of the Board not held concurrently or sequentially with a meeting of the Board of Directors of PG&E Corporation, or any meeting of a Board committee 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 meeting attended; provided, however, that non-employee directors attending any meeting of the Audit Committee of this Board which 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 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 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 attending Board or committee meetings; and

BE IT FURTHER RESOLVED that, effective as of January 1, 2008, the resolution on this subject adopted by the Board of Directors on December 20, 2006 is hereby superseded.

PG&E Corporation

2006 Long-Term Incentive Plan

PG&E Corporation

2006 Long-Term Incentive Plan

(As adopted effective January 1, 2006, and
as amended on February 15, 2006, December 20, 2006, and October 17, 2007)

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 Nominating, Compensation, and Governance 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.

(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) “ **Securities Act** ” means the Securities Act of 1933, as amended.

(ss) “ **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.

(tt) “ **Stock** ” means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(uu) “ **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.

(vv) “ **Subsidiary Corporation** ” means any present or future “subsidiary corporation” of the Company, as defined in Section 424(f) of the Code.

(ww) “ **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.

(xx) “ **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, 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 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

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 (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 thousand dollars (\$40,000) by the Fair Market Value of the Stock on the Grant Date, and rounding down to the nearest whole number.

(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 \$40,000, 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 \$20,000, 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 7.2 above, 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 or \$40,000 as previously elected by the Nonemployee Director (or \$20,000 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 7.2 above, 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 or \$40,000, as previously elected by the Nonemployee Director (or \$20,000 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). 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 only be made (a) after the Nonemployee Director's Mandatory Retirement from the Board, (b) if the Director ceases to be a member of the Board of Directors after five years of continuous service on the Board ("Director Retirement"), or (c) as provided in Section 7.5 below. 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. The Nonemployee Director may elect to receive the Stock in a lump sum distribution or in a series of ten or less approximately equal annual installments, provided that distribution shall commence no later than January of the year following the year in which the Nonemployee Director's Director Retirement or Mandatory Retirement occurred.

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; (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 and (3) all Restricted Stock Units credited to the Nonemployee Director's account shall immediately become payable 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; (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 and (3) all Restricted Stock Units credited to the Nonemployee Director's account shall immediately 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, (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 and (3) except as provided in Section 7.4(c), all Restricted Stock Units credited to the Participant's account shall be forfeited on the date of termination.

(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 be settled in accordance with Section 7.4(c) as if the Change of Control constituted Director Retirement.

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 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) , 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. 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 (or as soon thereafter as practicable) as the Restricted Stock Units originally subject to the Restricted 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 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:

- (i) shares of Stock otherwise issuable to such Participant upon the exercise of an Option;
- (ii) cash or shares of Stock otherwise issuable to such Participant upon the exercise of an SAR; or
- (iii) 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 (or as soon thereafter as practicable) 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. The Company shall issue to the Participant as soon as practicable following the earlier of the settlement date elected by the Participant or the date of termination of the Participant's 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 and all restrictions shall be released immediately prior to the Change in Control. 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.

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.

TABLE OF CONTENTS

	<u>Page</u>
1. Establishment, Purpose and Term of Plan	1
1.1 Establishment	1
1.2 Purpose	1
1.3 Term of Plan	1
2. Definitions and Construction	1
2.1 Definitions	1
2.2 Construction	7
3. Administration	7
3.1 Administration by the Committee	7
3.2 Authority of Officers	7
3.3 Administration with Respect to Insiders	8
3.4 Committee Complying with Section 162(m)	8
3.5 Powers of the Committee	8
3.6 Option or SAR Repricing	9
3.7 Indemnification	9
4. Shares Subject to Plan	10
4.1 Maximum Number of Shares Issuable	10
4.2 Adjustments for Changes in Capital Structure	10
5. Eligibility and Award Limitations	11
5.1 Persons Eligible for Awards	11
5.2 Participation	11
5.3 Incentive Stock Option Limitations	11
5.4 Award Limits	12
6. Terms and Conditions of Options	13
6.1 Exercise Price	13
6.2 Exercisability and Term of Options	13
6.3 Payment of Exercise Price	13
6.4 Effect of Termination of Service	14
6.5 Transferability of Options	14
7. Terms and Conditions of Nonemployee Director Awards	15
7.1 Automatic Grant of Restricted Stock	15
7.2 Annual Election to Receive Nonstatutory Stock Option and Restricted Stock Units	15
7.3 Grant of Nonstatutory Stock Option	15
7.4 Grant of Restricted Stock Unit	16
7.5 Effect of Termination of Service as a Nonemployee Director	17
7.6 Effect of Change in Control on Nonemployee Director Awards	18

7.7	Right to Decline Nonemployee Director Awards	18
8.	Terms and Conditions of Stock Appreciation Rights	19
8.1	Types of SARs Authorized	19
8.2	Exercise Price	19
8.3	Exercisability and Term of SARs	19
8.4	Deemed Exercise of SARs	19
8.5	Effect of Termination of Service	20
8.6	Nontransferability of SARs	20
9.	Terms and Conditions of Restricted Stock Awards	20
9.1	Types of Restricted Stock Awards Authorized	20
9.2	Purchase Price	20
9.3	Purchase Period	20
9.4	Vesting and Restrictions on Transfer	20
9.5	Voting Rights, Dividends and Distributions	21
9.6	Effect of Termination of Service	21
9.7	Nontransferability of Restricted Stock Award Rights	21
10.	Terms and Conditions of Performance Awards	21
10.1	Types of Performance Awards Authorized	22
10.2	Initial Value of Performance Shares and Performance Units	22
10.3	Establishment of Performance Period, Performance Goals and Performance Award Formula	
10.4	Measurement of Performance Goals	22
10.5	Settlement of Performance Awards	23
10.6	Voting Rights, Dividend Equivalent Rights and Distributions	24
10.7	Effect of Termination of Service	24
10.8	Nontransferability of Performance Awards	25
11.	Terms and Conditions of Restricted Stock Unit Awards	25
11.1	Grant of Restricted Stock Unit Awards	25
11.2	Vesting	25
11.3	Voting Rights, Dividend Equivalent Rights and Distributions	25
11.4	Effect of Termination of Service	26
11.5	Settlement of Restricted Stock Unit Awards	26
11.6	Nontransferability of Restricted Stock Unit Awards	26
12.	Deferred Compensation Awards	27
12.1	Establishment of Deferred Compensation Award Programs	27
12.2	Terms and Conditions of Deferred Compensation Awards	27

13.	Other Stock-Based Awards	28
14.	Change in Control	28
14.1	Effect of Change in Control on Options and SARs	28
14.2	Effect of Change in Control on Restricted Stock and Other Awards	29
14.3	Nonemployee Director Awards	29
15.	Compliance with Securities Law	29
16.	Tax Withholding	29
16.1	Tax Withholding in General	29
16.2	Withholding in Shares	30
17.	Amendment or Termination of Plan	30
18.	Miscellaneous Provisions	30
18.1	Repurchase Rights	30
18.2	Provision of Information	30
18.3	Rights as Employee, Consultant or Director	30
18.4	Rights as a Shareholder	31
18.5	Fractional Shares	31
18.6	Severability	31
18.7	Beneficiary Designation	31
18.8	Unfunded Obligation	31
18.9	Choice of Law	32

EXHIBIT 11
PG&E CORPORATION
COMPUTATION OF EARNINGS PER COMMON SHARE

(in millions, except per share amounts)	Year Ended December 31,		
	2007	2006	2005
Net Income	\$ 1,006	\$ 991	\$ 917
Less: distributed earnings to common shareholders	508	460	449
Undistributed earnings	498	531	468
Less: undistributed earnings from discontinued operations	-	-	13
Undistributed earnings from continuing operations	\$ 498	\$ 531	\$ 455
Common shareholder earnings			
Basic			
Distributed earnings to common shareholders	\$ 508	\$ 460	\$ 449
Undistributed earnings allocated to common shareholders - continuing operations	472	503	433
Undistributed earnings allocated to common shareholders - discontinued operations	-	-	12
Total common shareholders earnings, basic	\$ 980	\$ 963	\$ 894
Diluted			
Distributed earnings to common shareholders	\$ 508	\$ 460	\$ 449
Undistributed earnings allocated to common shareholders - continuing operations	473	504	433
Undistributed earnings allocated to common shareholders - discontinued operations	-	-	12
Total common shareholders earnings, diluted	\$ 981	\$ 964	\$ 894
Weighted average common shares outstanding, basic	351	346	372
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	370	365	391
Weighted average common shares outstanding, basic	351	346	372
Employee stock-based compensation and accelerated share repurchases ⁽¹⁾	2	3	6
Weighted average common shares outstanding, diluted	353	349	378
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	372	368	397
Net earnings per common share, basic			
Distributed earnings, basic ⁽²⁾	\$ 1.45	\$ 1.33	\$ 1.21
Undistributed earnings - continuing operations, basic	1.34	1.45	1.16
Undistributed earnings - discontinued operations, basic	-	-	0.03
Total	\$ 2.79	\$ 2.78	\$ 2.40
Net earnings per common share, diluted			
Distributed earnings, diluted	\$ 1.44	\$ 1.32	\$ 1.19
Undistributed earnings - continuing operations, diluted	1.34	1.44	1.15
Undistributed earnings - discontinued operations, diluted	-	-	0.03
Total	\$ 2.78	\$ 2.76	\$ 2.37

⁽¹⁾ Includes approximately one million and two million shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchase agreements (-ASRs-) for 2006 and 2005, respectively. The remaining shares of approximately two million at December 31, 2006 and four million at December 31, 2005 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,				
	2007	2006	2005	2004	2003
Earnings:					
Net income	\$ 1,024	\$ 985	\$ 934	\$ 3,982	\$ 923
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	571	602	574	2,561	528
Net fixed charges	889	801	589	671	964
Total Earnings	<u>\$ 2,484</u>	<u>\$ 2,388</u>	<u>\$ 2,097</u>	<u>\$ 7,214</u>	<u>\$ 2,415</u>
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	\$ 834	\$ 770	\$ 573	\$ 682	\$ 947
Interest on capital leases	23	11	1	1	1
AFUDC debt	32	20	15	(12)	16
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-
Total Fixed Charges	<u>\$ 889</u>	<u>\$ 801</u>	<u>\$ 589</u>	<u>\$ 671</u>	<u>\$ 964</u>
Ratios of Earnings to Fixed Charges	<u>2.79</u>	<u>2.98</u>	<u>3.56</u>	<u>10.75</u>	<u>2.51</u>

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 the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. Fixed charges exclude interest on FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes) tax liabilities..

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

	Year ended December 31,				
Earnings:	2007	2006	2005	2004	2003
Net income	\$ 1,024	\$ 985	\$ 934	\$ 3,982	\$ 923
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	571	602	574	2,561	528
Net fixed charges	889	801	589	671	964
Total Earnings	\$ 2,484	\$ 2,388	\$ 2,097	\$ 7,214	\$ 2,415
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	\$ 834	\$ 770	\$ 573	\$ 682	\$ 947
Interest on capital leases	23	11	1	1	1
AFUDC debt	32	20	15	(12)	16
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-
Total Fixed Charges	889	801	589	671	964
Preferred Stock Dividends:					
Tax deductible dividends	\$ 9	\$ 12	\$ 12	\$ 9	\$ 9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	8	3	13	34	27
Total Preferred Stock Dividends	17	15	25	43	36
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 906	\$ 816	\$ 614	\$ 714	\$ 1,000
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	2.74	2.93	3.42	10.10	2.42

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 the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. □Preferred stock dividends□ represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on FASB Interpretation No. 48 (Accounting for Uncertainty in Income Taxes) tax liabilities.

Contents

[Selected Financial Data](#)[Management's Discussion and Analysis of Financial Condition and Results of Operations](#)[Overview](#)[Forward-Looking Statements](#)[Results of Operations](#)[Liquidity and Financial Resources](#)[Contractual Commitments](#)[Capital Expenditures](#)[Off-Balance Sheet Arrangements](#)[Contingencies](#)[Regulatory Matters](#)[Risk Management Activities](#)[Critical Accounting Policies](#)[Accounting Pronouncements Issued But Not Yet Adopted](#)[Taxation Matters](#)[Environmental Matters](#)[Legal Matters](#)[Risk Factors](#)**PG&E Corporation**[Consolidated Statements of Income](#)[Consolidated Balance Sheets](#)[Consolidated Statements of Cash Flows](#)[Consolidated Statements of Shareholders' Equity](#)**Pacific Gas and Electric Company**[Consolidated Statements of Income](#)[Consolidated Balance Sheets](#)[Consolidated Statements of Cash Flows](#)[Consolidated Statements of Shareholders' Equity](#)[Notes to the Consolidated Financial Statements](#)[Note 1: Organization and Basis of Presentation](#)[Note 2: Summary of Significant Accounting Policies](#)[Note 3: Regulatory Assets, Liabilities, and Balancing Accounts](#)[Note 4: Debt](#)[Note 5: Rate Reduction Bonds](#)[Note 6: Energy Recovery Bonds](#)[Note 7: Discontinued Operations](#)[Note 8: Common Stock](#)[Note 9: Preferred Stock](#)[Note 10: Earnings Per Share](#)[Note 11: Income Taxes](#)[Note 12: Derivatives and Hedging Activities](#)[Note 13: Nuclear Decommissioning](#)[Note 14: Employee Compensation Plans](#)[Note 15: Resolution of Remaining Chapter 11 Disputed Claims](#)[Note 16: Related Party Agreements and Transactions](#)[Note 17: Commitments and Contingencies](#)[Quarterly Consolidated Financial Data \(Unaudited\)](#)[Management's Report on Internal Control Over Financial Reporting](#)[Report of Independent Registered Public Accounting Firm](#)

SELECTED FINANCIAL DATA

	2007	2006	2005	2004 ⁽¹⁾	2003
(in millions, except per share amounts)					
PG&E Corporation ⁽²⁾					
For the Year					
Operating revenues	\$ 13,237	\$ 12,539	\$ 11,703	\$ 11,080	\$ 10,435
Operating income	2,114	2,108	1,970	7,118	2,343
Income from continuing operations	1,006	991	904	3,820	791
Earnings per common share from continuing operations, basic	2.79	2.78	2.37	9.16	1.96
Earnings per common share from continuing operations, diluted	2.78	2.76	2.34	8.97	1.92
Dividends declared per common share ⁽³⁾	1.44	1.32	1.23	-	-
At Year-End					
Book value per common share ⁽⁴⁾	\$ 22.91	\$ 21.24	\$ 19.94	\$ 20.90	\$ 10.16
Common stock price per share	43.09	47.33	37.12	33.28	27.77
Total assets	36,648	34,803	34,074	34,540	30,175
Long-term debt (excluding current portion)	8,171	6,697	6,976	7,323	3,314
Rate reduction bonds (excluding current portion)	-	-	290	580	870
Energy recovery bonds (excluding current portion)	1,582	1,936	2,276	-	-
Financial debt subject to compromise	-	-	-	-	5,603
Preferred stock of subsidiary with mandatory redemption provisions	-	-	-	122	137
Pacific Gas and Electric Company					
For the Year					
Operating revenues	\$ 13,238	\$ 12,539	\$ 11,704	\$ 11,080	\$ 10,438
Operating income	2,125	2,115	1,970	7,144	2,339
Income available for common stock	1,010	971	918	3,961	901
At Year-End					
Total assets	\$ 36,326	\$ 34,371	\$ 33,783	\$ 34,302	\$ 29,066
Long-term debt (excluding current portion)	7,891	6,697	6,696	7,043	2,431
Rate reduction bonds (excluding current portion)	-	-	290	580	870
Energy recovery bonds (excluding current portion)	1,582	1,936	2,276	-	-
Financial debt subject to compromise	-	-	-	-	5,603
Preferred stock with mandatory redemption provisions	-	-	-	122	137

⁽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 7 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 quarter 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. See Note 8 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 10 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, 2007. The Utility had approximately \$36.3 billion in assets at December 31, 2007 and generated revenues of approximately \$13.2 billion in the twelve months ended December 31, 2007.

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 customers' 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 which the Utility is required to consolidate under applicable accounting standards and variable interest entities for which the Utility is subject to a majority of the risk of loss or gain. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations of PG&E Corporation and the Utility should be read in conjunction with the Consolidated Financial Statements and the Notes to the Consolidated Financial Statements included in this annual report.

Summary of Changes in Earnings per Common Share and Net Income for 2007

PG&E Corporation's diluted earnings per common share ("EPS") for 2007 was \$2.78 per share, compared to \$2.76 per share for 2006. For 2007, PG&E Corporation's net income increased by approximately \$15 million, or 2%, to \$1,006 million, compared to \$991 million in 2006. The increase in diluted EPS and net income for 2007 compared to 2006 is primarily due to positive regulatory outcomes, in combination with certain events that affected 2006 net income but did not recur in 2007.

Net income and EPS in 2007 reflect increased revenues of \$125 million associated with the Utility's return on equity ("ROE") on additional capital investments authorized by the CPUC in the Utility's General Rate Case ("GRC") effective January 1, 2007, and by the FERC in the Utility's transmission owner ("TO") rate case effective March 1, 2007. In addition, net income and EPS in 2007 were favorably affected on a comparative basis by approximately \$18 million, the amount of an environmental remediation charge taken in 2006 as a result of changes in the California Regional Water Control Board's imposed remediation levels. These increases were principally offset by amounts resulting from the following events that increased 2006 net income but did not recur in 2007: (1) the FERC's approval of recovery of scheduling coordinator ("SC") costs that the Utility began incurring in 1998 (representing a \$77 million decrease in net income as compared to 2006), (2) the recovery of certain interest and litigation costs following the CPUC's completion of a verification audit (representing a \$39 million decrease in net income as compared to 2006), (3) a decrease in the amount accrued for long-term disability benefits and a tax benefit recognized in 2006 related to a tax loss carry forward (representing a \$26 million decrease in net income as compared to 2006).

Key Factors Affecting Results of Operations and Financial Condition

PG&E Corporation's 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's and the Utility's results of operations and financial condition, including:

- The Outcome of Regulatory Proceedings* . The amount of the Utility's revenues and the amount of costs that the Utility is authorized to recover from customers are primarily determined through regulatory proceedings. The timing of CPUC and FERC decisions also affect when the Utility is able to record the authorized revenues. In March 2007, the CPUC issued a decision in the 2007 GRC, effective January 1, 2007, establishing a \$4.9 billion annual revenue requirement for the Utility's electric and natural gas distribution operations and its electric generation operations for 2007 through 2010, with authorized increases in each of 2008, 2009, and 2010. In June 2007, the FERC approved the Utility's annual electric transmission retail revenue requirement at \$674 million, effective March 1, 2007. In addition, in September 2007, the FERC accepted the Utility's proposed electric transmission retail revenue requirement effective March 1, 2008, subject to hearing and refund, an amount that would represent a revenue increase of approximately \$78 million over March 1, 2007 rates. In September 2007, the CPUC approved a multi-party settlement agreement (known as the Gas Accord IV) that establishes the Utility's natural gas transmission and storage rates and associated revenue requirements for 2008 through 2010, with 2008 rates set at \$446 million with slight escalations in each subsequent year. Finally, during 2007, the CPUC established incentive ratemaking mechanisms 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 incentives 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. The actual amount and timing of the financial impact will depend on the level of energy efficiency savings actually achieved over the three-year program cycle, the amount of the savings attributable to the Utility's energy efficiency programs, and when the applicable accounting standard for recognizing incentives or reimbursement obligations is met. The outcome of various other pending regulatory proceedings also could have a material effect on the Utility's results of operations. (See "Regulatory Matters" below.)
- Capital Structure and Return on Common Equity*. In 2007, the CPUC authorized the Utility to earn a ROE of 11.35% on its electric and natural gas distribution and electric generation rate base and to maintain an authorized capital structure that included a 52% common equity component. On December 20, 2007, the CPUC authorized the Utility to earn the same ROE and maintain the same capital structure in 2008. In December 2007, Moody's Investors Service ("Moody's") upgraded the Utility's credit rating to A3, thereby terminating a provision in the December 2003 settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11 Settlement Agreement") that had required the CPUC to authorize a minimum ROE for the Utility of 11.22% and a minimum common equity component of 52% until the Utility received a credit rating of "A3" from Moody's or "A-" from Standard & Poor's Ratings Service ("S&P"). (See "Liquidity and Financial Resources" below.)
- The Ability of the Utility to Control Costs and Achieve Operational Efficiencies and Improved Reliability* . The forecasted operating costs and capital expenditures used to set the revenue requirements authorized in the GRC reflected assumptions about future cost savings that were expected to be achieved through implementation of various initiatives intended to increase cost efficiencies, achieve operational excellence, and improve customer service. The cost of many of these initiatives is substantial, with savings expected to be realized in later years. If the actual cost savings exceed the contemplated savings, such benefits would accrue to shareholders. Conversely, to the extent that contemplated cost savings are not realized, earnings available for shareholders would be reduced. One major initiative involving new work processes, information systems and technology has resulted in significant delays and increased costs to respond to customer requests for new service, although the Utility is attempting to remedy the problems. The Utility also is undertaking a thorough review of its operating practices and procedures and, depending on the results of this review, may increase spending to address any identified issues associated with the reliability and safety of the electric and natural gas distribution systems. (See "Results of Operations – Operating and Maintenance" and "Risk Factors" below.) In addition to capital expenditures authorized to be recovered through GRC-authorized rates and FERC-authorized TO rates, the CPUC has authorized the Utility to make substantial capital expenditures to install an advanced metering infrastructure, to invest in new generation resources, and to improve existing generation facilities, as described below under "Capital Expenditures." The Utility will incur depreciation, property tax, and interest expense associated with these capital expenditures. The Utility's financial condition and results of operations will be impacted by its ability to manage its operating costs and capital expenditures within authorized revenues.

- *The Amount and Timing of Debt and Equity Financing Needs.* During 2007, the Utility issued \$1.2 billion of long-term debt to finance capital expenditures and for working capital. (See Note 4 of the Notes to the Consolidated Financial Statements.) The Utility's needs for additional financing in 2008 and future years will be affected by the amount and timing of capital expenditures as well as by the amount and timing of interest payments related to the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Disputed Claims"). (See Note 15 of the Notes to the Consolidated Financial Statements.) PG&E Corporation's and the Utility's financial condition and results of operations will be affected by the interest rates, timing, and terms and conditions of any such financing. PG&E Corporation plans to contribute equity to the Utility to maintain the Utility's authorized capital structure. The timing and amount of these equity contributions will affect the timing and amount of any new PG&E Corporation equity issuances and/or debt issuances which, in turn, will affect PG&E Corporation's results of operations and financial condition. (See "Liquidity and Financial Resources" below.)

In addition to the key factors discussed above, PG&E Corporation's and the Utility's future results of operation and financial condition are subject to the risk factors discussed in detail in "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, anticipated costs and savings associated with the Utility's efforts to implement changes to its business processes and systems, estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, estimated tax liabilities, the anticipated outcome of various regulatory and legal proceedings, 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," "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 operating costs within authorized levels and recover costs through rates in a timely manner;
- the outcome of regulatory proceedings, including pending and future ratemaking proceedings at the CPUC and the FERC;
- 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;
- 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 the Utility's Diablo Canyon nuclear generating facilities ("Diablo Canyon"), 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 efficiencies it has recognized from its completed initiatives to improve its business processes and customer service, improve its performance following the October 2007 implementation of new work processes and systems, and identify and successfully implement additional cost-saving measures;

- whether the Utility incurs substantial unanticipated expense to improve the safety and reliability of its electric and natural gas distribution 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 and/or the Utility to access capital markets and other sources of credit in a timely manner on favorable terms;
- 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 more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations, see the discussion under the heading “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 2007, 2006, and 2005:

(in millions)	Year ended December 31,		
	2007	2006	2005
Utility			
Electric operating revenues	\$ 9,481	\$ 8,752	\$ 7,927
Natural gas operating revenues	3,757	3,787	3,777
Total operating revenues	13,238	12,539	11,704
Cost of electricity	3,437	2,922	2,410
Cost of natural gas	2,035	2,097	2,191
Operating and maintenance	3,872	3,697	3,399
Depreciation, amortization, and decommissioning	1,769	1,708	1,734
Total operating expenses	11,113	10,424	9,734
Operating income	2,125	2,115	1,970
Interest income	150	175	76
Interest expense	(732)	(710)	(554)
Other income (expense), net ⁽¹⁾	38	(7)	-
Income before income taxes	1,581	1,573	1,492
Income tax provision	571	602	574
Income available for common stock	\$ 1,010	\$ 971	\$ 918
PG&E Corporation, Eliminations, and Other ⁽²⁾			
Operating revenues	\$ (1)	\$ -	\$ (1)
Operating (gain) expenses	10	7	(1)
Operating loss	(11)	(7)	-
Interest income	14	13	4
Interest expense	(30)	(28)	(29)
Other expense, net	(9)	(6)	(19)
Loss before income taxes	(36)	(28)	(44)
Income tax benefit	(32)	(48)	(30)
Income (loss) from continuing operations	(4)	20	(14)
Discontinued operations ⁽³⁾	-	-	13
Net income (loss)	\$ (4)	\$ 20	\$ (1)
Consolidated Total			
Operating revenues	\$ 13,237	\$ 12,539	\$ 11,703
Operating expenses	11,123	10,431	9,733
Operating income	2,114	2,108	1,970
Interest income	164	188	80
Interest expense	(762)	(738)	(583)
Other income (expense), net ⁽¹⁾	29	(13)	(19)
Income before income taxes	1,545	1,545	1,448
Income tax provision	539	554	544
Income from continuing operations	1,006	991	904
Discontinued operations ⁽³⁾	-	-	13
Net income	\$ 1,006	\$ 991	\$ 917

⁽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 its former subsidiary, National Energy & Gas Transmission, Inc ("NEG-T"). See Note 7 of the Notes to the Consolidated Financial Statements for further discussion.

Utility

The Utility's rates for electricity and natural gas services are determined based on its costs of service. The CPUC and the FERC determine the amount of "revenue requirements" that the Utility can collect to recover the Utility's reasonable operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas supplied to its customers. (See "Risk Management Activities" below.)

The GRC is the primary proceeding in which the CPUC determines the amount of revenue requirements that the Utility can recover for basic business and operational costs related to its electricity and natural gas distribution and electricity generation operations. The CPUC sets revenue requirements for a rate case period based on a forecast of costs for the first, or test, year. The CPUC may authorize the Utility to receive annual increases (known as attrition adjustments) for the years between GRCs in order to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. Effective January 1, 2007, the CPUC authorized the Utility to collect 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 attrition adjustments to authorized revenues of \$125 million in 2008 and 2009, and \$90 million in 2010. In addition, the decision authorizes 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.

Historically, the CPUC also has conducted an annual cost of capital 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 relative weightings of common equity, preferred equity, and debt in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on each component that the Utility will collect in its authorized rates. For 2006, 2007, and 2008, the CPUC has authorized an 11.35% ROE for the Utility and a capital structure that includes a 52% common equity component. The CPUC is expected to issue a decision in April 2008 addressing proposals to replace the annual cost of capital proceeding with an annual cost of capital adjustment mechanism for 2009 through 2013. (See "Regulatory Matters – 2008 Cost of Capital Proceeding" below.)

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 and ROE is the TO rate case. A TO rate case generally sets 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. In June 2007, the FERC approved a settlement that sets the Utility's annual transmission retail revenue requirement at \$674 million effective March 1, 2007.

The Utility's gas transmission and storage service, rates, and market structure are set by the CPUC. In September 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 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.

The Utility's revenues for natural gas transmission services may fluctuate because 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. The Utility's actual revenues for natural gas transmission service are based on actual volumes sold, accordingly, natural gas transmission service revenues are subject to volumetric risk. (See the "Natural Gas Transportation and Storage" section in "Risk Management Activities" below.)

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.

The Utility's rates reflect the sum of individual revenue requirement components authorized by the CPUC and the FERC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's results of operations. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed below under "Regulatory Matters." 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 2007, 2006, and 2005.

Electric Operating Revenues

The Utility provides electricity to residential, industrial, and small and large commercial customers through its own generation facilities and through contracts with third parties under power purchase agreements. 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.

The following table provides a summary of the Utility’s electric operating revenues:

	2007	2006	2005
(in millions)			
Electric operating revenue	\$ 11,710	\$ 10,871	\$ 9,626
DWR pass-through revenue ⁽¹⁾	(2,229)	(2,119)	(1,699)
Total electric operating revenue	\$ 9,481	\$ 8,752	\$ 7,927
Total electricity sales (in Gigawatt hours)	64,986	64,725	61,150

⁽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.

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 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 the number of reliability must run (“RMR”) agreements the Utility has with the CAISO and the associated costs. 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 costs, and the related revenues, will decline. (See “Cost of Electricity” below.)
- Revenues in 2006 included approximately \$136 million for recovery of SC 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 Energy Recovery Bonds (“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, including the recovery of a pension revenue requirement as authorized by the CPUC, decreased by approximately \$58 million.

The Utility’s electric operating revenues increased in 2006 by approximately \$825 million, or approximately 10%, compared to 2005 mainly due to the following factors:

- Electricity procurement costs, which are passed through to customers, increased by approximately \$490 million. (See “Cost of Electricity” below.)
- The dedicated rate component (“DRC”) charges related to the ERBs increased by approximately \$175 million. (See Notes 3 and 6 of the Notes to the Consolidated Financial Statements.) During 2005, the Utility collected only the DRC for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility collected the DRC associated with the first series of ERBs and the DRC related to the second series of ERBs, issued on November 9, 2005.
- As discussed above, in 2006, the Utility recognized approximately \$136 million following the FERC’s order allowing the Utility to recover SC costs that the Utility incurred from April 1998 through December 2005. No similar amount was recognized in 2005.
- The Utility recognized attrition adjustments to the Utility’s authorized 2003 base revenue requirements of approximately \$135 million, as authorized in the 2003 GRC.
- The Utility recorded approximately \$112 million in revenue requirements to recover a pension contribution attributable to the Utility’s electric distribution and generation operations, but no similar amount was recognized in 2005.
- Transmission revenues increased by approximately \$90 million primarily due to an increase in revenues, as authorized by the FERC.
- As discussed above, the Utility recognized approximately \$65 million due to the recovery of net interest costs related to Disputed Claims for the period between the effective date of the Utility’s plan of reorganization under Chapter 11 and the date the first series of ERBs was issued, and for certain energy supplier refund litigation costs, but no similar amount was recognized in 2005.
- The Utility recovered approximately \$59 million of net interest costs related to Disputed Claims incurred after the issuance of the first series of ERBs, as authorized by the CPUC, but no similar amount was recognized in 2005.

These were partially offset by the following:

- In 2005, the Utility recognized approximately \$160 million due to the resolution of the Utility’s claims for shareholder incentives related to energy efficiency and other public purpose programs, but no similar amount was recognized in 2006.
- In 2005, the Utility recognized approximately \$154 million related to revenue requirements associated with the settlement regulatory asset provided under the Chapter 11 Settlement Agreement and the recovery of costs on the deferred tax component of the settlement regulatory asset, but no similar amounts were recorded in 2006 after the refinancing of the settlement regulatory asset through the issuance of the ERBs.
- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs, decreased electric operating revenues by approximately \$123 million in 2006 from 2005. The second series of ERBs was issued to pre-fund the Utility’s tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility’s authorized rate of return on rate base to compensate them for the use of proceeds from the second series of ERBs as well as the after-tax proceeds of energy supplier refunds used to reduce the size of the second series of ERBs.

The Utility’s electric operating revenues for the period 2008 through 2010 are expected to increase, as authorized by the CPUC in the 2007 GRC and by the FERC in future TO rate cases. In addition, the Utility expects to continue to collect revenue requirements related to CPUC-approved capital expenditures, including the new Utility-owned generation projects and the SmartMeter™ project. (See “Capital Expenditures” below.) Revenue requirements associated with new or expanded public purpose programs, such as the California Solar Initiative, will result in increased electric operating revenues. In addition, the Utility may recognize incentive revenues to the extent it achieves the CPUC’s energy efficiency goals. Finally, future electric operating revenues will be impacted by changes in the cost of electricity.

Cost of Electricity

The Utility’s cost of electricity includes electricity purchase costs, hedging costs, and the cost of fuel used by its generation facilities or supplied to other facilities under tolling agreements. It excludes 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 therefore to sell this 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:

	2007	2006	2005
(in millions)			
Cost of purchased power ⁽¹⁾	\$ 3,443	\$ 3,114	\$ 2,706
Proceeds from surplus sales allocated to the Utility	(155)	(343)	(478)
Fuel used in own generation	149	151	182
Total cost of electricity	\$ 3,437	\$ 2,922	\$ 2,410
Average cost of purchased power per kWh	\$ 0.089	\$ 0.084	\$ 0.079
Total purchased power (in millions of kWh)	38,828	36,913	34,203

⁽¹⁾ Includes costs associated with RMR agreements.

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 kilowatt-hour ("kWh") from 2006 to 2007 primarily due to higher energy payments made to qualifying facilities ("QFs") 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 costs associated with RMR agreements.

The Utility's cost of electricity increased by approximately \$512 million, or 21%, in 2006 compared to 2005, mainly due to an increase in total purchased power of 2,710 million kWh, or 8%, and an increase in the average cost of purchased power of \$0.005 per kWh, or 6%, in 2006, compared to 2005. This was primarily caused by an increase in volume of purchased power due to greater customer demand during unseasonably warm weather during the summer of 2006 and a decrease in the volume of electricity provided by the DWR to the Utility's customers. Additionally, the Utility's service to customers who purchase "bundled" services (i.e., generation, transmission and distribution) grew, further increasing volume.

The Utility's cost of electricity in 2008 and future years will depend upon electricity and natural gas prices, the level of hydroelectric and nuclear power that the Utility produces, the cost of procuring more renewable energy, impacts from termination of DWR contracts, CPUC-ordered changes to QF pricing, and changes in customer demand. (See the "Risk Management Activities – Price Risk" below.)

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. As directed by recent California legislation, the CPUC has already adopted an interim greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility. (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, in competition with interstate pipelines.

The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial customers. The non-core customer class is comprised of industrial and larger

commercial 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 2007, core customers represented over 99% of the Utility's total customers and approximately 38% of its total natural gas deliveries, while non-core customers comprised less than 1% of the Utility's total customers and approximately 62% of its total natural gas deliveries. As discussed above, because the Utility sells most of its transportation services under volumetric rates, the Utility is exposed to volumetric revenue risk.

The following table provides a summary of the Utility's natural gas operating revenues:

	2007	2006	2005
(in millions)			
Bundled natural gas revenues	\$ 3,417	\$ 3,472	\$ 3,539
Transportation service-only revenues	340	315	238
Total natural gas operating revenues	\$ 3,757	\$ 3,787	\$ 3,777
Average bundled revenue per Mcf of natural gas sold	\$ 12.93	\$ 12.89	\$ 13.05
Total bundled natural gas sales (in millions of Mcf)	264	269	271

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 bundled natural gas revenues of approximately \$55 million, or 2%, as a result of decreases in the cost of natural gas, which are 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 SmartMeterTM project.

The Utility's natural gas operating revenues increased by approximately \$10 million, or less than one percent, in 2006 compared to 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- The Utility recorded approximately \$43 million in revenue requirements for a pension contribution attributable to the Utility's natural gas distribution operations, but no similar amount was recorded in 2005.
- Attrition adjustments to the Utility's 2003 GRC authorized revenue requirements and revenues authorized in the 2006 cost of capital proceeding contributed approximately \$22 million.
- Miscellaneous natural gas revenues increased by approximately \$26 million.
- Transportation service-only revenues increased by approximately \$77 million, or 32%, as a result of an increase in volume and a slight increase in rates as authorized by the CPUC.

These increases were partially offset by the following:

- The cost of natural gas, which is passed through to customers, decreased by approximately \$132 million.
- In 2005, the Utility recognized approximately \$26 million due to the resolution of the Utility's claims for shareholder incentives related to energy efficiency and other public purpose programs, but no similar amount was recorded in 2006.

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 following table provides a summary of the Utility's cost of natural gas:

	2007	2006	2005
(in millions)			
Cost of natural gas sold	\$ 1,859	\$ 1,958	\$ 2,051
Cost of natural gas transportation	176	139	140
Total cost of natural gas	\$ 2,035	\$ 2,097	\$ 2,191
Average cost per Mcf of natural gas sold	\$ 7.04	\$ 7.28	\$ 7.57
Total natural gas sold (in millions of Mcf)	264	269	271

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 thousand cubic feet ("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 has 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 total cost of natural gas decreased by approximately \$94 million, or 4%, in 2006 compared to 2005, primarily due to a decrease in the average market price of natural gas purchased of approximately \$0.29 per Mcf, or 4%. This decrease was primarily due to significantly higher than average market prices throughout 2005 as a result of severe weather conditions and a strong hurricane season as compared to the same period in 2006.

The Utility's cost of natural gas in subsequent periods will be primarily determined by market forces in North America. Market forces include supply availability, customer demand, and industry perceptions of risks that may affect either, such as the possibility of hurricanes in the gas-producing regions of the Gulf of Mexico or of protracted heat waves that may increase gas-fired electric demand from high air conditioning loads.

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. Generally, these expenses are offset by corresponding revenues authorized by the CPUC and the FERC in various proceedings.

The Utility's operating and maintenance expenses increased by approximately \$175 million, or 5%, in 2007 compared to 2006, mainly due to the following factors:

- Payments for customer assistance and public purpose programs, such as the California Solar Initiative program and the Mass Market 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 incentives.
- 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. (See Note 17 "California Labor Code Issues" of the Notes to the Consolidated Financial Statements.)
- Workers' compensation expense increased by approximately \$20 million due to a decrease to the discount rate on the workers' compensation 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.

The above 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.

During 2006, the Utility's operating and maintenance expenses increased by approximately \$298 million, or 9%, compared to 2005, mainly due to the following factors:

- Pension expense increased approximately \$176 million as a result of a CPUC-approved settlement to recover pension contributions.
- Expenses for customer assistance and public purpose programs increased approximately \$125 million.
- Compensation expense increased approximately \$54 million reflecting increased base salaries and incentives.
- Costs, including outside consulting fees, related to the Utility's continued efforts to achieve operating efficiencies increased approximately \$50 million.
- The Utility accrued approximately \$35 million for severance costs in connection with the Utility's continued efforts to eliminate and consolidate various employee positions in numerous Utility locations (see Note 17 of the Notes to the Consolidated Financial Statements).
- Franchise fee expense and property taxes increased by approximately \$21 million. The increase in franchise fee expense was due to higher revenues and franchise fee rates. The increase in property taxes was due to electric plant growth, tax rate increases, and increases in assessed values in 2006.

The above increases were offset by a decrease of \$154 million related to an additional reserve made in 2005 to settle the majority of claims related to alleged exposure to chromium at the Utility's natural gas compressor stations. No similar adjustment was recorded in 2006.

Operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, the timing and length of Diablo Canyon refueling outages, environmental remediation costs, legal costs, material costs, and various other administrative and general expenses. The Utility anticipates that it will incur higher material, permitting, and labor costs (including potential wage increase of newly union organized classifications resulting from collective bargaining) in the future as well as higher costs to operate and maintain its aging infrastructure. The Utility also expects that employee severance costs will increase as the Utility continues its efforts to achieve cost and operating efficiencies. The Utility anticipates that it will make additional payments to employees for missed or delayed meals to comply with California labor law as the Utility's investigation into this matter continues. (See Note 17 of the Notes to the Consolidated Financial Statements for a discussion of severance costs and California labor code issues.) In addition, the Utility may incur costs, not included in forecasts used to set rates in the GRC, to address safety and reliability issues in the Utility's electric and natural gas distribution system depending on the outcome of its review of its operating practices and procedures following recent electric transformer failures and the discovery that some natural gas maintenance records did not accurately reflect field conditions. (See "Risk Factors" below.) The Utility also expects that it will incur higher expenses in subsequent periods to comply with the requirements of renewed hydroelectric generation licenses and to complete the construction of the dry cask storage facility at Diablo Canyon. The Utility's operating and maintenance expenses will also increase in the first quarter of 2008 due to the planned refueling outage at Diablo Canyon Unit 2. The Utility anticipates that the refueling outage will last approximately 76 days, which is longer than the average outage duration, in order for the Utility to replace the steam generators in Unit 2.

Depreciation, Amortization, and Decommissioning

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 plant additions in 2007 authorized by the 2007 GRC decision. This was partially offset by:

- 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 decreased by approximately \$26 million, or 1%, in 2006 compared to 2005, reflecting the following factors:

- The Utility recorded approximately \$141 million in 2005 for amortization of the settlement regulatory asset. The settlement regulatory asset was refinanced with the issuance of the first series of ERBs on February 10, 2005. The Utility recorded approximately \$137 million in 2006 related to the amortization of the ERB regulatory asset. During 2005, the Utility amortized only the ERB regulatory asset for the first series of ERBs that were issued on February 10, 2005. During 2006, the Utility amortized the ERB regulatory asset for the second series of ERBs that were issued on November 9, 2005 in addition to the first series. Although the Utility did not have a similar expense related to the settlement regulatory asset in 2006.
- In 2005, the Utility recorded depreciation expense of approximately \$30 million related to recovery of capital plant costs associated with electric industry restructuring costs that a December 2004 settlement agreement allowed the Utility to collect through rates in 2005. There was no similar depreciation expense in 2006.
- Amortization of the regulatory asset related to Rate Reduction Bonds ("RRBs"), decreased by approximately \$19 million in 2006, compared to 2005, due to the declining balance of the RRBs.

These were partially offset by the following:

- Depreciation expense increased by approximately \$35 million as a result of plant additions in 2006.

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.

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 SC 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 Internal Revenue Service refund claims. In addition, other interest income, including interest income associated with certain balancing accounts, increased by approximately \$6 million.

The Utility's interest income increased by approximately \$99 million, or 130%, in 2006 compared to 2005, primarily due to an increase in interest earned on escrow related to Disputed Claims, the FERC's approval of the Utility's recovery of SC costs, including interest, and an increase in interest rates associated with certain regulatory balancing accounts. These increases were partially offset by a decrease in interest earned in 2006, as compared to 2005, on short-term investments as a result of lower short-term investment balances.

The Utility's interest income in 2008 will be primarily affected by changes in the amount of escrowed funds related to Disputed Claims and interest rate levels.

Interest Expense

The Utility's interest expense increased by approximately \$22 million, or 3%, in 2007 compared to 2006, primarily due to an approximately \$19 million increase in interest expense related to Disputed Claims primarily due to an increase in the 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 ERBs and RRBs as their balances decline. In addition, other interest expense, including lower interest expense on balances in certain regulatory balancing accounts, decreased approximately \$3 million.

In 2006, the Utility's interest expense increased by approximately \$156 million, or 28%, compared to 2005, primarily due to an increase in interest expense related to Disputed Claims, interest expense associated with the ERBs, and accrued interest on higher balances in certain regulatory balancing accounts. Increased interest rates associated with these accounts also contributed to this higher interest expense. These increases were partially offset by lower interest expense on the declining balance of RRBs.

The Utility's interest expense in 2008 will be impacted by changes in interest rates as the Utility's short-term debt and a portion of its long-term debt bear variable interest rates, as well as by changes in the amount of debt, including debt expected to be issued in subsequent periods to finance capital expenditures. (See "Liquidity and Financial Resources" below.)

Income Tax Expense

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, mainly 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.

The Utility's income tax expense increased by approximately \$28 million, or 5%, in 2006 compared to 2005, primarily due to an increase in pre-tax income of \$79 million for 2006. The effective tax rate was 38.0% for both 2006 and 2005.

PG&E Corporation, Eliminations and Others

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 income in 2007 compared to 2006 and in 2006 compared to 2005.

Income Tax Benefit

PG&E Corporation's income tax benefit in 2007 decreased approximately \$16 million, or 33%, compared to 2006 primarily due to a tax benefit booked in 2006 related to capital losses carried forward and used in PG&E Corporation's 2005 consolidated federal and state income tax returns with no comparable benefit in 2007.

PG&E Corporation's income tax benefit in 2006 increased approximately \$18 million, or 60%, compared to 2005 primarily due to tax benefits related to capital losses carried forward and used in PG&E Corporation's 2005 consolidated federal and state income tax returns.

Discontinued Operations

In 2005, PG&E Corporation received additional information from its former subsidiary, NEGT, regarding PG&E Corporation's 2004 and 2003 federal income tax returns. As a result, PG&E Corporation recorded \$13 million in income from discontinued operations in 2005. (See Note 7 of the Notes to the Consolidated Financial Statements.)

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The level of PG&E Corporation's and the Utility's current assets and current liabilities may fluctuate as a result of seasonal demand for electricity and natural gas, energy commodity costs, collateral requirements, the timing and effect of regulatory decisions and financings, and the amount and timing of capital expenditures, among other factors.

PG&E Corporation and the Utility manage liquidity and debt levels in order to meet expected operating and financial needs and maintain access to credit for contingencies. At December 31, 2007, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately \$345 million and restricted cash of approximately \$1.3 billion. At December 31, 2007, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$204 million; the Utility had cash and cash

equivalents of approximately \$141 million and restricted cash of approximately \$1.3 billion. Restricted cash primarily consists of approximately \$1.2 billion of cash held in escrow pending the resolution of the remaining Disputed Claims as well as deposits made under certain third-party agreements. PG&E Corporation and the Utility maintain separate bank accounts. PG&E Corporation and the Utility primarily invest their cash in money market funds.

PG&E Corporation and the Utility seek to maintain or strengthen their credit ratings in order to provide liquidity through efficient access to financial and trade credit, and to reduce financing costs. PG&E Corporation and the Utility also seek to maintain the Utility's CPUC-authorized capital structure which includes a 52% common equity component. In 2007, Moody's upgraded the Utility's credit rating to A3, thereby terminating a provision in the Chapter 11 Settlement Agreement that had required the CPUC to authorize a minimum 52% common equity ratio and a minimum ROE for the Utility of 11.22% until the Utility received a credit rating of A3 from Moody's or A- from S&P. On December 20, 2007, the CPUC issued a decision maintaining the Utility's authorized ROE at 11.35% and its common equity component at 52% for 2008.

As of February 2008, PG&E Corporation's and the Utility's credit ratings from Moody's and 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	AA/A-1+
Pollution control bonds backed by bond insurance	A3 to Aaa	AA to AAA
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.

As of December 31, 2007, PG&E Corporation had a credit facility totaling \$200 million which can be increased to \$300 million, subject to obtaining commitments from existing or new lenders and satisfying other conditions. As of December 31, 2007, the Utility had a credit facility totaling \$2.0 billion ("working capital facility") which can be increased to \$3.0 billion, subject to obtaining commitments from existing or new lenders and satisfying other conditions. During 2007, the Utility increased its borrowing capacity under its commercial paper program from \$1.0 billion to \$1.75 billion. As of December 31, 2007, the Utility had \$165 million of letters of credit and \$250 million of borrowings outstanding under its working capital facility. As of December 31, 2007, the Utility also had \$270 million of outstanding commercial paper. In order to satisfy rating agency criteria, the Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its working capital facility. As authorized by the CPUC, the total amount of the Utility's short-term debt at any time cannot exceed \$2 billion (plus up to an additional \$500 million for specific contingencies). At December 31, 2007, the Utility had \$1.3 billion of short-term debt capacity available (in addition to \$500 million of debt capacity for specific contingencies).

In 2005, the Utility purchased a financial guaranty insurance policy to insure the regularly scheduled payment of principal and interest on \$454 million of pollution control bonds series 2005 A-G ("PC2005 bonds") issued by the California Infrastructure and Economic Development Bank. In January 2008, the insurer's credit rating was downgraded and/or put on review for possible downgrade by several credit agencies. This has resulted in increases in interest rates for the PC2005 bonds, which rates are currently set at auction every 7 or 35 days. To minimize this interest rate exposure, the Utility intends to exercise its right to purchase the bonds in lieu of redemption and remarket the bonds when market conditions are more favorable. The purchase of the PC2005 bonds is expected to be financed through issuance of long-term debt.

As discussed below in "Capital Expenditures," the Utility expects that its capital expenditures will average approximately \$3.4 billion over each of the next four years. Subject to additional CPUC authorization as needed, the Utility forecasts that it will issue an average of \$1.4 billion of long-term debt annually for each of the next four years (2008-2011), primarily to finance forecasted capital expenditures. During 2007, the Utility issued \$700 million principal amount of 5.80% 30-year Senior Notes and \$500 million

principal amount of 5.625% 10-year Senior Notes. As the level of Utility debt increases, the Utility anticipates that it will need to issue additional common equity to maintain the 52% CPUC-authorized common equity component of its capital structure. During 2007, PG&E Corporation made equity contributions totaling \$400 million to the Utility to meet a portion of the Utility's forecasted equity needs. PG&E Corporation anticipates that it will contribute \$2 billion to \$2.5 billion of additional equity to the Utility over the next four years to maintain the Utility's CPUC-authorized capital structure.

PG&E Corporation anticipates that it will fund a portion of future equity infusions to the Utility from the proceeds of common stock issued (1) upon exercise of employee stock options, (2) to the trustee of PG&E Corporation's 401(k) plan for employee-participant accounts, and (3) under the PG&E Corporation Dividend Reinvestment and Stock Purchase Plan ("DRSPP"), which became effective on October 1, 2007. During the year ended December 31, 2007, PG&E Corporation issued 5,038,197 shares of common stock upon the exercise of employee stock options, for the account of 401(k) plan participants, and under its DRSPP, generating approximately \$175 million of cash. PG&E Corporation also expects to issue additional common stock, debt, or other securities, depending on market conditions, to fund a portion of the Utility's future equity needs.

The amount and timing of the Utility's future financing needs will depend on various factors, including: (1) the timing and amount of forecasted capital expenditures and any incremental capital expenditures beyond those currently forecasted; (2) the amount of cash internally generated through normal business operations; and (3) the timing of the resolution of the Disputed Claims (upon settlement or the conclusion of the FERC and judicial proceedings) 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.) PG&E Corporation will continue to evaluate how to best fund the Utility's future equity needs considering such factors as the timing and amount of the Utility's future financings, market conditions, and available interest rates and credit terms.

In addition, PG&E Corporation may issue additional debt, equity, or other securities to finance potential capital investments.

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's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- **Sustainability:** Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

The target dividend payout ratio range is 50% to 70% of PG&E Corporation's earnings. Dividends are expected to remain in the lower end of PG&E Corporation's target payout ratio range to ensure that equity funding is readily available to support capital investment needs. The Boards of Directors retain authority to change the companies' respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change the Boards' view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

During 2007, the Utility paid cash dividends to holders of various series of preferred stock in the aggregate amount of \$14 million. In addition, on February 15, 2008, the Utility paid cash dividends of \$3 million to holders of preferred stock.

During 2007, the Utility paid common stock dividends of \$547 million. Approximately \$509 million of this amount was paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility that holds approximately 7% of the Utility's common stock.

On March 16, 2007, the Board of Directors of PG&E Corporation declared its quarterly dividend at \$0.36 per share, an increase of \$0.03 per share over the previous level of \$0.33 per share. During 2007, PG&E Corporation paid common stock dividends of \$529 million, including approximately \$35 million paid to Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation that holds approximately 6% of PG&E Corporation's common stock. On January 15, 2008, PG&E Corporation paid common stock dividends of \$137 million, including \$9 million paid to Elm Power Corporation. On February 20, 2008, the Board of Directors of PG&E Corporation declared its quarterly dividend at \$0.39 per share, an increase of \$0.03 per share over the previous level of \$0.36 per share, payable on April 15, 2008 to shareholders of record on March 31, 2008.

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 2007, 2006 and 2005 were as follows:

	2007	2006	2005
(in millions)			
Net income	\$ 1,024	\$ 985	\$ 934
Adjustments to reconcile net income to net cash provided by operating activities	2,122	1,573	1,082
Other changes in operating assets and liabilities	(605)	19	350
Net cash provided by operating activities	<u>\$ 2,541</u>	<u>\$ 2,577</u>	<u>\$ 2,366</u>

Net cash provided by operating activities decreased by approximately \$36 million in 2007 from 2006. The decrease primarily relates to a decline in cash settlements from energy suppliers in 2007 as compared to 2006. This decrease was offset primarily by an increase in net income in 2007 as compared to 2006.

Net cash provided by operating activities increased by approximately \$211 million in 2006 from 2005. In addition to the increase in net income, net cash provided by operating activities increased primarily due to the following factors:

- The Utility paid approximately \$500 million less in net tax payments in 2006 as compared to 2005.
- Deferred income taxes and tax credits decreased by approximately \$350 million, 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.
- Cash settlements with energy suppliers declined by approximately \$140 million in 2006 as compared to 2005.

These increases were partially offset by the following:

- Approximately \$290 million of pension contributions were made during 2006 but not in 2005.
- Approximately \$295 million was paid in April 2006 to settle the majority of claims relating to alleged exposure to chromium at the Utility's natural gas compressor stations.
- The Utility had approximately \$125 million in additional costs primarily related to power and gas procurement that were unpaid at the end of 2005, compared to the end of 2006, primarily due to higher gas prices during 2005.

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. The level of 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 as well as by storms and other factors.

The Utility's cash flows from investing activities for 2007, 2006 and 2005 were as follows:

	2007	2006	2005
(in millions)			
Capital expenditures	\$ (2,768)	\$ (2,402)	\$ (1,803)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Other investing activities, net	(103)	(156)	(29)
Net cash used in investing activities	<u>\$ (2,665)</u>	<u>\$ (2,426)</u>	<u>\$ (1,359)</u>

Net cash used in investing activities increased by approximately \$239 million in 2007 compared to 2006, primarily due to an

increase of approximately \$370 million in capital expenditures for the SmartMeter™ installation project, generation facility spending, replacing and expanding gas and electric distribution systems, and improving the electric transmission infrastructure. (See “Capital Expenditures” below.)

Net cash used in investing activities increased by approximately \$1 billion in 2006 compared to 2005, primarily due to approximately \$600 million of capital expenditures related to software improvements, the SmartMeter™ project, generation facilities, the improvement of the gas and electric distribution system, and the improvement of the electric transmission infrastructure. In addition, the Utility released \$300 million more cash from escrow in 2005 upon settlement of Disputed Claims than in 2006.

Financing Activities

The Utility’s cash flows from financing activities for 2007, 2006, and 2005 were as follows:

	<u>2007</u>	<u>2006</u>	<u>2005</u>
(in millions)			
Borrowings under accounts receivable facility and working capital facility	\$ 850	\$ 350	\$ 260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of \$1 million in 2007 and \$2 million in 2006	(209)	458	-
Net proceeds from issuance of long-term debt	1,184	-	451
Net proceeds from issuance of energy recovery bonds	-	-	2,711
Long-term debt, matured, redeemed or repurchased	-	-	(1,554)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock dividends paid	(14)	(14)	(16)
Common stock dividends paid	(509)	(460)	(445)
Preferred stock with mandatory redemption provisions redeemed	-	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	-	(37)
Equity Infusion from PG&E Corporation	400	-	-
Common stock repurchased	-	-	(1,910)
Other	23	38	65
Net cash provided by (used in) financing activities	<u>\$ 195</u>	<u>\$ (544)</u>	<u>\$ (1,327)</u>

In 2007, net cash provided by financing activities increased by approximately \$739 million compared to 2006. This was mainly due to the following factors:

- The Utility issued Senior Notes in March and December 2007 for net proceeds of approximately \$690 million and \$494 million, respectively, with no similar issuances in 2006.
- The Utility received equity infusions of \$400 million from PG&E Corporation in 2007, with no similar infusions in 2006.
- The Utility borrowed \$500 million more under its working capital facility in 2007 as compared to 2006.
- The Utility repaid \$590 million more under its working capital and accounts receivable facilities in 2007 as compared to 2006.
- The Utility made net commercial paper repayments of approximately \$209 million in 2007 as compared to net borrowings of \$458 million in 2006.
- The Utility paid approximately \$49 million more in common stock dividends in 2007 than in 2006.

In 2006, net cash used in financing activities decreased by approximately \$783 million compared to 2005. This was mainly due to the following factors:

- The Utility had net issuances of \$458 million in commercial paper in 2006 with no similar issuance in 2005.
- In 2005, the Utility repurchased \$1.9 billion in common stock from PG&E Corporation. There were no common stock repurchases in 2006.
- The Utility received proceeds of \$2.7 billion from the issuance of ERBs in 2005.

- In May 2005, the Utility borrowed \$451 million from the California Infrastructure and Economic Development Bank, which was funded by the bank's issuance of Pollution Control Bonds Series A-G, with no similar borrowing in 2006.
- The amount of ERBs that matured in 2006 was approximately \$175 million greater than the amount that matured in 2005 .
- The Utility borrowed \$90 million more from the accounts receivable facility during 2006, as compared to 2005.
- The Utility redeemed \$122 million of preferred stock in 2005 with no similar redemption in 2006.
- In 2005, the Utility redeemed \$500 million and defeased \$600 million of Floating Rate First Mortgage Bonds (redesignated as Senior Notes in April 2005). The Utility also repaid \$454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code became effective. There were no similar redemptions or repayments in 2006.

PG&E Corporation

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility for services rendered and payments for employee compensation and goods and services provided by others to PG&E Corporation. PG&E Corporation also incurs interest costs associated with its debt.

PG&E Corporations' consolidated cash flows from operating activities for 2007, 2006 and 2005 were as follows:

	<u>2007</u>	<u>2006</u>	<u>2005</u>
(in millions)			
Net income	\$ 1,006	\$ 991	\$ 917
Gain on disposal of NEGT (net of income tax benefit of \$13 million in 2005)	-	-	13
Net income from continuing operations	1,006	991	904
Adjustments to reconcile net income to net cash provided by operating activities	2,141	1,611	1,122
Other changes in operating assets and liabilities	(601)	112	383
Net cash provided by operating activities	<u>\$ 2,546</u>	<u>\$ 2,714</u>	<u>\$ 2,409</u>

In 2007, net cash provided by operating activities decreased by \$168 million as compared to 2006. The decrease is primarily related to tax refunds received by PG&E Corporation in 2006 with no similar refunds received in 2007 and a decrease in the Utility's net cash provided by operating activities.

In 2006, net cash provided by operating activities increased by \$305 million compared to 2005, primarily due to an increase in the Utility's net cash provided by operating activities and tax refunds received by PG&E Corporation during the first and third quarters of 2006 will no similar refunds received during 2005.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material cash flows associated with investing activities in the years ended December 31, 2007, 2006, and 2005.

Financing Activities

PG&E Corporation's primary sources of financing funds, on a stand-alone basis, are dividends from the Utility, equity issuances, and external financing. PG&E Corporation's uses of cash, on a stand-alone basis, primarily relate to the payment of common stock dividends and common stock repurchases.

PG&E Corporation's cash flows from financing activities for 2007, 2006, and 2005 were as follows:

	2007	2006	2005
(in millions)			
Borrowings under accounts receivable facility and working capital facility	\$ 850	\$ 350	\$ 260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of \$1 million in 2007 and \$2 million in 2006	(209)	458	-
Net proceeds from issuance of long-term debt	1,184	-	451
Net proceeds from issuance of energy recovery bonds	-	-	2,711
Long-term debt matured, redeemed or repurchased	-	-	(1,556)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock with mandatory redemption provisions redeemed	-	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	-	(37)
Common stock issued	175	131	243
Common stock repurchased	-	(114)	(2,188)
Common stock dividends paid	(496)	(456)	(334)
Other	35	3	32
Net cash provided by (used in) financing activities	<u>\$ 9</u>	<u>\$ (544)</u>	<u>\$ (1,270)</u>

During 2007, PG&E Corporation's consolidated net cash provided by financing activities increased by approximately \$553 million compared to 2006. The decrease in cash used after consideration of the Utility's cash flows provided by financing activities, was primarily due to the payment of \$114 million in 2006 to settle obligations related to the 2005 repurchase of common stock, with no similar payments in 2007.

During 2006, PG&E Corporation's consolidated net cash used in financing activities decreased by approximately \$726 million compared to 2005 primarily due to the following factors, after consideration of the Utility's cash flows from financing activities:

- PG&E Corporation paid four quarterly common stock dividends in 2006, but made only three payments in 2005.
- In 2005, PG&E Corporation repurchased approximately \$2.2 billion in common stock. There was no similar share repurchase in 2006, but PG&E Corporation paid \$114 million to settle obligations related to 2005 stock repurchase.

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2007. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These future obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities. (See Note 17 of the Notes to the Consolidated Financial Statements.)

	Payment due by period				
	Total	Less than One year	1-3 years	3-5 years	More than 5 years
(in millions)					
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements ⁽¹⁾ :					
Qualifying facilities	\$ 17,185	\$ 1,770	\$ 3,248	\$ 2,891	\$ 9,276
Irrigation district and water agencies	479	83	164	107	125
Renewable contracts	8,783	245	672	1,026	6,840
Other power purchase agreements	716	238	386	79	13
Natural gas supply and transportation	1,446	1,181	244	21	-
Nuclear fuel	1,083	82	195	186	620

Preferred dividends ⁽²⁾	70	14	28	28	-
Other Commitments ⁽³⁾	26	24	2	-	-
Pension and other benefits ⁽⁴⁾	900	300	600	-	-
Operating leases	112	19	27	38	28
Long-term debt ⁽⁵⁾ :					
Fixed rate obligations	13,910	368	1,303	1,161	11,078
Variable rate obligations	1,796	28	53	688	1,027
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Energy recovery bonds ⁽⁶⁾	2,177	435	871	871	-
Capital lease obligations ⁽⁷⁾	503	50	100	100	253
PG&E Corporation					
Long-term debt ⁽⁵⁾ :					
Convertible subordinated notes	345	27	318	-	-

⁽¹⁾ This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts and payments. See Note 17 of the Notes to the Consolidated Financial Statements for the Utility's contractual commitments including power purchase agreements (including agreements with qualifying facility co-generators ("QFs") irrigation districts, and water agencies and renewable energy providers), natural gas supply and transportation agreements, and nuclear fuel agreements .

⁽²⁾ Preferred dividend estimates beyond five years are not included as these dividend payments continue in perpetuity.

⁽³⁾ Includes commitments for telecommunications and information system contracts in the aggregate amount of approximately \$6 million, vehicle leasing arrangements in the aggregate amount of \$3 million, and SmartMeter TM contracts in the aggregate amount of approximately \$17 million.

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

⁽⁶⁾ Includes interest payments over the terms of the bonds. (See Note 6 of the Notes to the Consolidated Financial Statements.)

⁽⁷⁾ See Note 17 of the Notes to the Consolidated Financial Statements.

The contractual commitments table above excludes potential commitments associated with the conversion of existing overhead electric facilities to underground electric facilities. At December 31, 2007, the Utility was committed to spending approximately \$236 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 \$50 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"). On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of FIN 48. (See "Adoption of New Accounting Pronouncements" in Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the impact of adoption and the unrecognized tax benefits balance as of December 31, 2007.) 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 in Note 11 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled \$2.8 billion in 2007, \$2.4 billion in 2006, and \$1.9 billion in 2005. The Utility expects that capital expenditures will total approximately \$3.6 billion in 2008 and forecasts that capital expenditures will average approximately \$3.4 billion over each of the next four years. The Utility's weighted average rate base in 2007 was \$16.8 billion. Based on the estimated capital expenditures for 2008 and 2009, the Utility projects a weighted average rate base of approximately \$18.4 billion for 2008 and approximately \$20.8 billion for 2009.

The Utility forecasts that it will make various capital investments in its electric and gas transmission and distribution infrastructure to maintain and enhance system reliability and customer service, to extend the life of or replace existing infrastructure, to add new infrastructure to meet already authorized growth, and to implement various initiatives designed to achieve operating and cost efficiencies. The Utility also is exploring obtaining regulatory approval for potential investments in electric transmission projects including the proposed 500 kV Central California Clean Energy Transmission project and a proposed new high voltage transmission

line to run between Northern California and British Columbia, Canada. In addition, as discussed below, the Utility has been incurring substantial capital expenditures in connection with projects that have already begun, including the construction or acquisition of new generation facilities and the installation of an advanced metering system.

PG&E Corporation also may make material investments in two natural gas transmission pipeline projects through 2011: the proposed 230-mile Pacific Connector Gas Pipeline that would begin at the proposed Jordan Cove liquefied natural gas (“LNG”) terminal to be located in Coos Bay, Oregon and connect with the Utility’s transmission system near Malin, Oregon, and the proposed 680-mile Ruby Pipeline that would begin in Wyoming and terminate at the Malin, Oregon interconnect, near California’s northern border. 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 Pacific Connector Gas Pipeline which is dependent upon the development of the Jordan Cove LNG terminal by Fort Chicago Partners, L.P. In September 2007, applications with the FERC were filed to request authorization to construct the proposed Pacific Connector Gas Pipeline and the Jordan Cove LNG terminal. It is expected that the FERC will issue a decision by the end of 2008. Assuming the required permits, regulatory approvals, and long-term capacity commitments for both the terminal and pipeline are timely received and that other conditions are timely satisfied, it is anticipated that the proposed LNG terminal and the proposed Pacific Connector Gas Pipeline could begin commercial operation in 2011. In December 2007, PG&E Corporation entered into a letter of intent with El Paso Corporation to acquire a 25.5 percent interest in El Paso Corporation’s proposed Ruby Pipeline. PG&E Corporation’s acquisition of an interest in the Ruby Pipeline project is subject to various conditions, including the negotiation and execution of the partnership documents. Subject to obtaining the required regulatory and other approvals, including the approvals of the boards of directors of PG&E Corporation and El Paso Corporation, and after obtaining necessary customer commitments, the Ruby Pipeline is anticipated to be in service in the first quarter of 2011. PG&E Corporation cannot predict whether the regulatory approvals and other conditions for development of the Pacific Connector Gas Pipeline and the Ruby Pipeline will be met.

SmartMeter™ Program

In July 2006, the CPUC approved the Utility’s application to install 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 demand-response rates. The main goal of demand-response 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 began installation of the infrastructure in 2006 and 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 the 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 2007, the Utility has spent an aggregate of \$253 million, including capital costs of \$213 million, to install the SmartMeter™ system.

On December 12, 2007, the Utility filed an application with the CPUC requesting approval to upgrade elements of the SmartMeter™ program at an estimated cost of approximately \$623 million, including approximately \$565 million of capital expenditures. The Utility has proposed to install upgraded electric meters with associated devices that would offer an expanded range of service features for customers and increased operational efficiencies for the Utility. These upgraded electric meters and devices would provide energy conservation and demand response options for 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. The Utility also requested that the CPUC authorize the Utility to recover the estimated costs of the upgrade through electric rates beginning in 2009. PG&E Corporation and the Utility cannot predict whether the CPUC will approve its application.

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). The CPUC authorized the Utility to recover costs of this project of 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, 2007, the Utility has spent approximately \$300 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 \$373 million. The Utility began installing four of the new steam generators in Unit 2 during the refueling outage that began in February 2008 and expects to complete installation in April 2008. The remaining new generators in Unit 1 are expected to be installed in 2009.

The Utility has obtained two coastal development permits from the California Coastal Commission to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation and for certain offloading activities. The Utility also has a conditional use permit from San Luis Obispo County to store the old generators on site at Diablo Canyon. On January 10, 2007, the Coastal Law Enforcement Action Network filed a complaint in the Superior Court for the County of San Francisco against both the California Coastal Commission and the Utility alleging that the California Coastal Commission violated the California Coastal Act, the California Environmental Quality Act, and the San Luis Obispo Certified Local Coastal Program when it approved the permits without requiring the Utility to commit to undertake certain proposed or otherwise feasible mitigation measures. The complaint requests that the court (1) find that the approval of the permits was “illegal and invalid,” (2) order the commission to set aside and vacate its approval, and (3) issue a permanent injunction to prohibit the Utility from engaging in any activity authorized by the permits until the California Coastal Commission complies with the judgment that the court may render. The court denied the request for a permanent injunction in April 2007. Further proceedings on the complaint have been delayed at the request of all parties in support of ongoing discussions regarding informal resolution of the complaint. PG&E Corporation and the Utility believe that the permits were legally and validly approved and issued.

If the replacement of the steam generators in Unit 1 is delayed, the Utility could incur additional costs to operate and maintain the old steam generators in Unit 1 until they can be replaced which would delay and extend project completion dates. If the Utility is not able to replace the generators in Unit 1, the Utility would be required to cease operations at Diablo Canyon Unit 1 and procure power from other sources when the generators are no longer operable in conformance with operating standards. The Utility would also have to pay for all work done in connection with the design and fabrication of the four steam generators and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated. Based on the progress of the project and productive settlement discussion, the Utility does not expect to incur these additional costs. In the unlikely event that replacement of the generators in Unit 1 is halted or delayed, the Utility would request to recover in customer rates any additional costs.

New Generation Facilities

During 2007, 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 (“Gateway”). The CPUC has authorized the Utility to recover estimated capital costs of approximately \$370 million to complete the construction of the facility. During 2007, the Utility incurred approximately \$119 million related to the Gateway project. The Utility estimates that it will complete construction of the Gateway facility and commence operations in 2009.

- *Colusa Power Plant*

In November 2006, the CPUC approved the purchase and sale agreement between the Utility and E&L Westcoast, LLC (“E&L Westcoast”) under which E&L Westcoast had agreed to construct a 657-MW power plant in Colusa County, California (“Colusa Project”) and, upon successful completion, transfer ownership to the Utility. The CPUC adopted an initial capital cost for the Colusa Project that equals the sum of the fixed contract costs, the Utility’s estimated owner’s costs and a contingency amount to account for the risk and uncertainty in the estimation of owner’s costs. (Owner’s costs include the Utility’s expenses for legal, engineering and consulting services as well as the costs for internal personnel and overhead related to the project.) The Utility estimates that the cost to complete the Colusa Project will be approximately \$673 million, including owner’s costs. The CPUC authorized the Utility to adjust the initial capital costs for the Colusa Project 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 forecasted initial capital cost of the Colusa Project will be trued up in the Utility’s next GRC following the commencement of operations to reflect actual initial capital costs. 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. During 2007, the Utility incurred approximately \$12 million related to the Colusa Project.

In January 2008, the Utility acquired the assets related to the Colusa Project from E&L Westcoast after E&L Westcoast notified the Utility in November 2007 that it intended to terminate the purchase and sale agreement. On January 29, 2008, a proposed decision was issued that recommends that the CPUC issue a Certificate of Public Convenience and Necessity (“CPCN”) to allow the Utility to begin the construction of the Colusa Project subject to the initial capital cost limits and operations and maintenance ratemaking as described above. Permitting or construction delays and project development or materials cost overruns could cause the project costs to exceed the CPUC-adopted cost limits. The Utility has signed a contract with a major equipment supplier and has given a limited notice to proceed to a contractor to begin engineering and procurement activities. Subject to the timely issuance of a CPCN, the issuance of other required permits, operational performance requirements and other conditions, it is anticipated that the Colusa Project will commence operations in 2010.

- *Humboldt Bay Power Plant*

In November 2006, the CPUC also approved an agreement for 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. The CPUC adopted an initial capital cost of the Humboldt Bay project equal to the sum of the fixed contract costs plus the Utility’s estimated owner’s costs, but limited the contingency amount for owner’s costs to 5% of the fixed contract costs and estimated owner’s costs. The CPUC authorized the Utility to adjust the initial capital costs 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 forecasted initial capital costs will be trued up in the Utility’s next GRC following the commencement of operations of the plant to reflect actual initial capital costs and all cost savings, if any. 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. 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 at an estimated cost of approximately \$239 million, of which approximately \$4 million has been incurred since 2007.

On December 20, 2007, the CPUC approved, with modifications, the California investor-owned electric utilities’ long-term electricity procurement plans covering 2007-2016. The CPUC’s decision forecasts that the Utility will need to obtain an additional 800 to 1,200 MW of new generation by 2015 beyond the Utility’s planned additions of renewable resources, energy efficiency, and demand reduction programs. The decision allows the utilities to acquire ownership of new conventional generation resources only through turnkey and engineering, procurement, and construction arrangements proposed by third parties. The decision prohibits the utilities from submitting bids for utility-build generation in their respective requests for offers (“RFOs”) until questions can be resolved about how to compare utility-owned generation bids with bids from independent power producers. The decision also permits utility-owned generation projects to be proposed 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 expand existing facilities, (4) to take advantage of a unique and fleeting opportunity (such as a bankruptcy settlement), and (5) to meet unique reliability needs. The decision allows the utilities to make flexible proposals for utility-owned generation ratemaking on a case-by-case basis by eliminating the 2004 CPUC limitations that prohibited the utilities from recovering construction costs in excess of their final bid price from customers but required the utilities to share half of any construction cost savings with customers.

PG&E Corporation and the Utility cannot predict whether any of this forecasted demand will be met through new utility-owned generation projects on which the Utility would be authorized to earn an ROE.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize certain arrangements that are not reflected in their Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation's or the Utility's activities or a significant ongoing source of financing. These arrangements enable PG&E Corporation and the Utility to obtain financing or execute commercial transactions on more favorable terms. For further information related to letter of credit agreements, the credit facilities and PG&E Corporation's guarantee related to certain NEGТ indemnity obligations, see Notes 4 and 17 of the Notes to the Consolidated Financial Statements.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if customers or counterparties failed to perform their contractual obligations. The Utility is exposed to a concentration of credit risk associated with receivables from the sale of natural gas and electricity to residential and small commercial customers in northern and central California. This credit risk exposure is mitigated by requiring deposits from new customers and from those customers whose past payment practices are below standard. A material loss associated with the regional concentration of retail receivables is not considered likely.

Additionally, the Utility has a concentration of credit risk associated with its 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. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Utility may find it necessary to procure electricity 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.

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. Further, 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, 2007 and December 31, 2006:

	Gross Credit Exposure Before Credit Collateral ⁽¹⁾		Credit Collateral	Net Credit Exposure ⁽²⁾		Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
(in millions)							
December 31, 2007	\$	311	\$	91	\$	220	2 \$ 111
December 31, 2006	\$	255	\$	87	\$	168	2 \$ 113

⁽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.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed in Note 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.

2008 Cost of Capital Proceeding

On December 20, 2007, the CPUC issued a decision in its proceeding to set the 2008 capital structure and ROEs of the three California investor-owned electric utilities. The CPUC maintained the Utility’s authorized ROE at 11.35%, comparable to the ROEs approved for the other utilities, and maintained the Utility’s common equity component at 52%. The following table compares the authorized amounts for 2007 with the authorized amounts for 2008:

	2007 Authorized			2008 Authorized		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Long-term debt	6.02%	46.00%	2.77%	6.05%	46.00%	2.78%
Preferred stock	5.87%	2.00%	0.12%	5.68%	2.00%	0.11%
Common equity	11.35%	52.00%	5.90%	11.35%	52.00%	5.90%
Return on rate base			8.79%			8.79%

In a second phase of the proceeding, the Utility has also proposed to replace the annual cost of capital proceeding with an annual cost of capital adjustment mechanism for the five-year period from 2009 through 2013. The mechanism would utilize an interest rate benchmark to trigger changes in the authorized cost of equity. If the change is more than 75 basis points, the cost of equity would be adjusted by one-half the change in the benchmark interest rate. The costs of debt and preferred stock would be trued up to their recorded values in each year. Other parties, including The Utility Reform Network (“TURN”), Utility Consumers’ Action Network, Southern California Edison, and the CPUC’s Division of Ratepayer Advocates (“DRA”) have submitted proposals to continue the annual proceeding or adopt a biennial proceeding.

A final decision in the second phase is scheduled to be issued by April 24, 2008. PG&E Corporation and the Utility are unable to predict the outcome of this phase of the proceeding.

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 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. On January 15, 2008, the NRC decided to hold hearings on whether it provided a complete list of the references upon which it relied to find that there would not be a significant environmental impact and whether it sufficiently addressed the impacts on land and the local economy of a potential terrorist attack. It is expected that the NRC will issue a final decision in the third quarter of 2008.

The Utility expects to complete the dry cask storage facility and begin loading spent fuel in 2008. If the Utility is unable to complete the dry cask storage facility, if operation of the facility is delayed beyond 2010, or if the Utility is otherwise unable to

increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 until such time as additional safe storage for spent fuel is made available.

The Utility and other nuclear power plant owners have sued the DOE for breach of contract. The Utility seeks to recover its costs to develop on-site storage at Diablo Canyon and Humboldt Bay Unit 3. In October 2006, the U.S. Court of Federal Claims found that the DOE had breached its contract and awarded the Utility approximately \$42.8 million of the \$92 million incurred by the Utility through 2004. The Utility appealed to the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenged the U.S. Court of Federal Claims' finding that the Utility would have incurred some of the costs for the on-site storage facilities even if the DOE had complied with the contract. A decision on the appeal is expected by the end of 2008. The Utility will seek to recover costs incurred after 2004 in future lawsuits against the DOE. Any 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 this appeal or the amount of any additional awards that the Utility may receive. If the U.S. Court of Federal Claims' decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for on-site storage facilities from the DOE. However, reasonably incurred costs related to the on-site storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

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.

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.

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 megawatt-hour (“MWh”) that applies to the spot market (i.e., real-time, hour-ahead and day-ahead markets) throughout the Western Electricity Coordinating Council 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 price “hard” caps of \$500/MWh when MRTU begins, rising to \$750/MWh after the twelfth month of MRTU, and finally to \$1000/MWh after the twenty-fourth month. The CAISO has delayed the start date of MRTU several times and has indicated that it will not set a new date for commencement of MRTU until market participants have had an opportunity to test the final MRTU system functionality and have provided feedback to the CAISO.

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, or entering into new 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, 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 these 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. On January 23, 2008, the Utility filed an application with the CPUC to adjust rates to recover the additional \$531 million in net procurement costs that the Utility expects to incur in 2008 due to the termination of the contract between the DWR and Calpine Corporation, discussed above. Because the DWR’s procurement costs will be lower due to the termination of this contract, the Utility also has requested that the CPUC reduce the corresponding amount of DWR procurement costs that the Utility collects from its customers on the DWR’s behalf. 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 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”), taking energy that passes between those locations. The CAISO also will provide Congestion Revenue Rights (“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, 2007 and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date. The CRRs are accounted for as derivative instruments and will be recorded in PG&E Corporation’s and the Utility’s Consolidated Balance Sheets at fair value. Changes in the fair value of the CRRs will be deferred and recorded in regulatory accounts to the extent they are recoverable through rates.

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 75% 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.

On June 7, 2007, the CPUC issued a decision approving a long-term hedging program for the Utility’s core gas purchases. The decision approved a settlement agreement between the Utility and three major consumer advocate groups that represent the interests of core customers, including the DRA, Aglet Consumer Alliance, and TURN. In addition, as part of the long-term core hedge program settlement, the Utility and the DRA agreed to modify the CPIM sharing provision for cost savings below the tolerance band to 20% shareholder and 80% customers, beginning with the 2007-2008 CPIM cycle (November 1, 2007 through October 31, 2008).

Under the decision, the long-term core hedge program will be in place for up to five years starting with the 2007-2008 winter season. The Utility consults with an advisory group, consisting of members of the three core gas consumer advocate groups, before submitting its annual hedging plan to the CPUC for approval. The Utility’s hedging costs will be recovered from its core gas customers as long as the CPUC finds that the Utility implemented its hedges in accordance with the pre-approved plan. All costs and benefits associated with hedging purchases under the approved annual hedging plan will be accounted for outside the CPIM.

The Utility’s filed core hedge plan prescribes the financial hedges that will be put in place on a rolling three-year basis (the current winter season and the next two subsequent winter seasons), consistent with pre-defined hedge program parameters. The CPUC approved the 2007-2008 winter season annual hedge plan on June 26, 2007. The Utility completed the execution of its hedge plan in the third quarter of 2007.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from one to thirteen 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 faces price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that is used to serve non-core customers. This risk is mitigated to the extent these non-core customers contract for transportation and storage services under firm service agreements that provide for recovery of substantial costs through reservation charges. The reservation charges under such contracts typically cover approximately 65% of the Utility's total cost of service. Price risk and volumetric risk result from variability in the price of and demand for natural gas transportation and storage services, respectively. Transportation and storage services are sold at both tariffed rates and competitive market-based rates within a cost-of-service framework.

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 99% confidence level, which means that there is a 1% 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 \$31 million and \$26 million at December 31, 2007 and December 31, 2006, respectively. The Utility's high, low, and average value-at-risk during the years ended December 31, 2007 and December 31, 2006 were approximately \$39 million, \$21 million, and \$29 million, and \$41 million, \$22 million, and \$33 million, respectively.

Convertible Subordinated Notes

At December 31, 2007, PG&E Corporation had outstanding approximately \$280 million of Convertible Subordinated Notes that 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 approximately 18,558,059 shares of common stock of PG&E Corporation, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment for significant changes in the number of PG&E Corporation's outstanding common shares. 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. PG&E Corporation paid "pass-through dividends" to the holders of Convertible Subordinated Notes of approximately \$26 million in 2007 and approximately \$7 million on January 15, 2008. Since no holders of the Convertible Subordinated Notes exercised the one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, PG&E Corporation reclassified the Convertible Subordinated Notes as a noncurrent liability (in Noncurrent Liabilities - Long-Term Debt) in the accompanying Consolidated Balance Sheets effective as of that date.

In accordance with Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities," the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Dividend participation rights are recognized as financing cash flows on 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, Net). At December 31, 2007 and December 31, 2006, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$62 million and \$79 million, respectively, of which \$25 million and \$23 million, respectively, was classified as a current liability (in Current Liabilities - Other) and \$37 million and \$56 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other).

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, 2007, 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 by approximately \$3 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with the accounting principles generally accepted in the United States of America 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

PG&E Corporation and the Utility account 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, 2007, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$5.2 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$5.1 billion.

Unbilled Revenues

The Utility records revenue as electricity and natural gas are delivered. Amounts delivered to customers are determined through the systematic readings of customer meters performed on a monthly basis. At the end of each month, the electric and gas usage from the last meter reading is estimated and corresponding unbilled revenue is recorded. The estimate of unbilled revenue is determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns.

In the following month, the estimate for unbilled revenue is reversed and actual revenue is recorded based on meter readings. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, and changes in the composition of customer classes. At December 31, 2007, accrued unbilled revenues totaled \$750 million.

Environmental Remediation Liabilities

Given the complexities of the legal and regulatory environment regarding environmental laws, the process of estimating environmental remediation liabilities is a subjective one. 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, 2007, the Utility's accrual for undiscounted and gross environmental liabilities was approximately \$528 million. The Utility's undiscounted future costs could increase to as much as \$834 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.

The accrual for undiscounted and gross environmental liabilities is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not probable are included in the estimation.

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.

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, if the inflation adjustment increased 25 basis points, this would increase the balance for ARO by approximately 1.26%. Similarly, an increase in the discount rate by 25 basis points would decrease ARO by 0.95%. At December 31, 2007, the Utility's estimated cost of retiring these assets is approximately \$1.6 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," which requires judgment regarding the potential tax effects of various transactions and ongoing operations to determine obligations owed to tax authorities. 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.

On January 1, 2007, PG&E Corporation and the Utility adopted the provisions of FIN 48. (See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.)

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 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, significant portions of 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 \$117 million in 2007, \$185 million in 2006, and \$176 million in 2005 in accordance with the provisions of SFAS No. 87. PG&E Corporation's and the Utility's recorded expense for other postretirement benefits totaled \$44 million in 2007, \$49 million in 2006, and \$55 million in 2005 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, 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 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, PG&E Corporation and the Utility have not identified any minimum funding requirements related to its pension plans.

In July 2006, the CPUC approved the Utility's 2006 Pension Contribution Application 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 expect to make total contributions of approximately \$176 million annually for the years 2008, 2009, and 2010. PG&E Corporation and the Utility made total contributions of approximately \$38 million in 2007 related to their other postretirement benefit plans and expect to make contributions of approximately \$58 million annually for the years 2008, 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 Retirement Plan, the assumed return of 7.4% compares to a ten-year actual return of 7.9%.

The rate used to discount pension and other postretirement benefit plan liabilities was based on a yield curve developed from market data of over 500 Aa-grade non-callable bonds at December 31, 2007. 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:

	<u>Increase (decrease) in Assumption</u>	<u>Increase in 2007 Pension Costs</u>	<u>Increase in Projected Benefit Obligation at December 31, 2007</u>
(in millions)			
Discount rate	(0.5)%	\$ 22	\$ 612
Rate of return on plan assets	(0.5)%	44	-
Rate of increase in compensation	0.5%	18	129

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

	<u>Increase (decrease) in Assumption</u>	<u>Increase in 2007 Other Postretirement Benefit Costs</u>	<u>Increase in Accumulated Benefit Obligation at December 31, 2007</u>
(in millions)			
Health care cost trend rate	0.5%	\$ 6	\$ 32
Discount rate	(0.5)%	7	76

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

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 defines fair value measurements and implements a hierarchical disclosure.

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 now 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 which gives precedence to fair value measurements calculated using observable inputs to 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."

Level 2: "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly."

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.

SFAS No. 157 requires entities to disclose financial fair-valued instruments according to the above hierarchy in each reporting period after implementation. The standard deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 should be applied prospectively except if certain criteria are met. CRRs held by the Utility meet the criteria and will be adjusted upon adoption to comply with SFAS No. 157 requirements. CRRs allow market participants, including LSEs, to hedge the financial risk of CAISO-imposed congestion charges in the MRTU day-ahead market. PG&E Corporation and the Utility are still evaluating the impact of the adjustment to price risk management assets and regulatory liabilities on their Consolidated Balance Sheets. The costs associated with procurement of CRRs are currently being recovered in rates or are probable of recovery in future rates; therefore, the adoption of SFAS No. 157 will not have an impact on net income.

Fair Value Option

In February 2007, the FASB issued 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. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility do not expect the adoption of SFAS No. 159 to materially impact the financial statements.

Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued FASB Staff Position on Interpretation 39, “Amendment of FASB Interpretation No. 39” (“FIN 39-1”). Under FIN 39-1, a reporting entity is permitted to offset the fair value amounts recognized for 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. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, and will affect the Utility’s Consolidated Balance Sheets as of March 31, 2008. The impact of FIN 39-1 on PG&E Corporation’s and the Utility’s balance sheets is currently being evaluated. PG&E Corporation and the Utility do not expect any earnings impact as a result of the adoption of the amendment, as FIN 39-1 only affects the balance sheet.

TAXATION MATTERS

See Note 11 of the Notes to the Consolidated Financial Statements for discussion of taxation matters.

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 reasonably likely 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, 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 reasonably 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 \$528 million at December 31, 2007 and approximately \$511 million at December 31, 2006. The \$528 million accrued at December 31, 2007 consists of:

- Approximately \$235 million for remediation at the Hinkley and Topock natural gas compressor sites;
- Approximately \$90 million related to remediation at divested generation facilities;
- Approximately \$152 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 the fossil decommissioning sites.

Of the approximately \$528 million environmental remediation liability, approximately \$132 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately \$306 million will be allowable for inclusion 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.

The Utility’s undiscounted future costs could increase to as much as \$834 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. The amount of approximately \$834 million does not include an 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.

In July 2004, the U.S. Environmental Protection Agency ("EPA") published regulations under Section 316(b) of the Clean Water Act that apply to existing electricity generation facilities that use over 50 million gallons of water per day, which typically include some form of "once-through" cooling in which water from natural bodies of water is used to cool a generating facility and the heated water is discharged back into the source. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The EPA regulations are intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations allow site-specific compliance measures if a facility's cost of compliance is significantly greater than either the benefits to be achieved or the compliance costs considered by the EPA. The EPA regulations also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, in June 2006, the California State Water Resources Control Board ("Water Board") published a draft policy for California's implementation of Section 316(b) that proposes to eliminate the EPA's site-specific compliance options, although the draft state policy would permit environmental restoration as a compliance option for nuclear facilities if the installation of cooling towers would conflict with a nuclear safety requirement. Various parties separately challenged the EPA's regulations in court, and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit ("Second Circuit"). In January 2007, the Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost-benefit test could not be used to comply with performance standards or to obtain a variance from the standards. The Second Circuit also ruled that environmental restoration cannot be used to comply with the standard. Petitions requesting U.S. Supreme Court review of the Second Circuit decision are pending, and the EPA has suspended its regulations. It is uncertain when the EPA will issue revised regulations, whether the Supreme Court will accept review of the Second Circuit decision, how judicial developments will affect the EPA's revised regulations, how judicial developments and the EPA's revised regulations will affect the Water Board's proposed policy, and when the Water Board will issue its final policy. Depending on the nature 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.

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, 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 provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, 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's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's Current Liabilities - Other in the Consolidated Balance Sheets, and totaled approximately \$78 million at December 31, 2007 and approximately \$74 million at December 31, 2006.

After considering the above accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material impact on their financial condition or results of operations.

RISK FACTORS

Risks Related to PG&E Corporation

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.

In approving the original formation of a holding company for the Utility, the CPUC imposed certain conditions, 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 these obligations could require PG&E Corporation to infuse the Utility with significant capital

in the future, or could prevent distributions from the Utility, either of which could materially restrict PG&E Corporation's ability to meet other obligations or execute its business strategy.

Adverse resolution of pending litigation could have a material, adverse effect on PG&E Corporation's financial condition and results of operation and cash flows.

In 2002, the California Attorney General and the City and County of San Francisco filed complaints against PG&E Corporation alleging that certain conditions imposed by the CPUC in approving the holding company formation, including the so-called "first priority condition," were violated and that these alleged violations constituted unfair or fraudulent business acts or practices in violation of Section 17200 of the California Business and Professions Code. The complaints allege that transfers of 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, violated holding company conditions. The complaints also allege that PG&E Corporation wrongfully failed to provide adequate financial support to the Utility in 2000 and 2001 during the California energy crisis. 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. An adverse outcome in this matter could have a material, adverse affect on PG&E Corporation's financial condition, results of operations and cash flows.

PG&E Corporation's proposed investments in new natural gas pipeline projects may not materialize and PG&E Corporation may be unable to finance such investments on favorable terms or rates.

The completion of PG&E Corporation's anticipated capital investment projects in proposed new natural gas pipelines projects, as discussed in "Capital Expenditures" above, is subject to various regulatory approvals and many construction and development risks, including risks related to financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, meeting environmental performance standards, and obtaining capacity commitments from shippers. Many of these conditions must be satisfied by PG&E Corporation's investment partners and PG&E Corporation will not be able to control whether the conditions are satisfied.

PG&E Corporation's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in PG&E Corporation's credit ratings, changes in the federal or state regulatory environment affecting energy companies, and general economic and market conditions. There can be no assurance that PG&E Corporation will be able to obtain financing with favorable terms and conditions, or at all.

Risks Related to the Utility

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, as well as an adequate return of and on the capital invested in its utility assets, including the 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 CPUC also has approved various programs to support public policy goals through the use of customer incentives, subsidies for energy efficiency programs, and the development and use of renewable and self-generation technologies. These and other similar incentives and subsidies increase the Utility's overall costs. As rate pressure increases, the risk increases 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.

Further, 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, there

can be no assurance that the CPUC will find that all of the Utility's costs are reasonable and prudent, or that the CPUC will not otherwise take or fail to take actions that would be to the Utility's detriment.

In addition, there can be no assurance that the bankruptcy court or other courts will implement and 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. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. 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 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. It is uncertain when MRTU will become effective. 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 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, 2007 and anticipates acquiring additional CRRs through the allocation and auction phases prior to the MRTU effective date.

In addition, it is anticipated that the CPUC will issue a decision in May 2008 that may change its current resource adequacy program which requires all LSEs to maintain physical generating capacity adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves, deliverable to locations and at times as may be necessary to provide reliable electric service. If the CPUC makes comprehensive changes to the program, such as replacing the current structure with a centralized capacity market similar to the organized capacity markets that operate in the Eastern United States, the Utility may be required to procure some or all of the capacity it needs through a centralized market instead of through bilateral contracts. It is uncertain how the Utility's resource adequacy obligations and related costs may change. Implementation of a centralized capacity market would require changes to the CAISO tariff and FERC approval.

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 be unable to identify and implement new initiatives to achieve operating and capital cost savings and operating efficiencies to compensate for the lower levels of realized and forecasted benefits from implemented initiatives and to offset potential increases in operating and maintenance costs to improve the safety and reliability of its electric and natural gas distribution systems.

During 2006, the Utility began to implement various initiatives to change its business processes and systems so as to achieve operational excellence and to provide better, faster and more cost-effective service to its customers. The cost of many of these initiatives is substantial, with savings expected to be realized in later years. The settlement of the Utility's 2007 GRC contemplated a certain level of benefits of cost savings attributable to implementation of these initiatives in 2008, 2009 and 2010. If the actual cost savings exceed the contemplated savings, such benefits would accrue to shareholders. Conversely, to the extent that contemplated

cost savings are not realized, earnings available for shareholders would be reduced. Although the Utility has realized many of the projected benefits, actual results from some of these initiatives have been less than forecasted. One major initiative involving new work processes, information systems and technology has resulted in significant delays in responding to customer requests for new service, although the Utility is attempting to remedy the problems. If the Utility is unable to identify and implement new cost-saving initiatives, or promptly fix the problems with customer requests for new service, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows would be adversely affected.

The Utility may fail to recognize the benefits of its advanced metering system or the advanced metering system may fail to perform as intended, resulting in higher costs and/or reduced cost savings.

During 2006, the Utility began to implement the SmartMeterTM 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. In December 2007, the Utility has requested the CPUC to approve certain upgrades to the advanced metering infrastructure and to authorize related revenue requirements of approximately \$623 million, including approximately \$565 million of forecasted capital expenditures.

If the Utility fails to recognize the expected benefits of its advanced metering infrastructure, if the Utility incurs additional costs that the CPUC does not find reasonable, 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.

The Utility faces significant 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. On February 28, 2008, the CPUC is scheduled to vote on a proposed decision that concludes that the CPUC does not have the authority to reinstate the ability of the Utility's customers to become direct access customers because the DWR still supplies power under the contracts it executed during

the energy crisis. The proposed decision states that the CPUC will proactively investigate how the DWR can terminate its obligations under the power contracts, by assignment or otherwise, to hasten the reinstatement of direct access. Separately, the CPUC has adopted rules to implement California Assembly Bill 117 that 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. 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 intends to begin operating in 2008. 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 a general economic downturn or if higher energy prices in California due to stricter greenhouse gas regulations or other state regulations cause customers to leave the Utility's service territory.

If the Utility experiences a material loss of customers or reduction of demand by customers, the Utility's existing electricity purchase contracts could obligate it to purchase more electricity than its remaining customers require. This would result in a long position and require the Utility to sell the excess, possibly at a loss. In addition, excess electricity generated by the Utility's 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 relies on access to the capital markets. There can be no assurance that the Utility will be able to successfully finance its planned capital expenditures on favorable terms or rates.

The Utility's ability to make scheduled principal and interest payments, refinance debt, and fund operations and planned capital expenditures depends on its operating cash flow and access to the capital markets. The CPUC has authorized the Utility to make substantial capital investments in electric transmission to secure access to renewable generation resources and to accommodate system load growth, in natural gas transmission to improve reliability and expand capacity and to replace aging or obsolete infrastructure (e.g., pipelines, storage facilities and compressor stations) to maintain system reliability, and in the electric and gas distribution system. In addition, the Utility expends capital to replace, refurbish or extend the life of its existing nuclear, hydroelectric and fossil facilities. The CPUC also has authorized the Utility to make capital investments in several new generation facilities. The Utility's ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in the Utility's credit ratings, changes in the federal or state regulatory environment affecting energy companies, increased or natural volatility in electricity or natural gas prices and general economic and market conditions.

PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected if the Utility is unable to obtain financing with favorable terms and conditions, or at all.

The completion of the Utility's capital investment projects is subject to substantial risks and the rate at which the Utility invests capital will directly affect net income.

The completion of the Utility's anticipated capital investment projects in existing and new generation facilities, electric and gas transmission, and electric and gas distribution systems is subject to many construction and development risks, including risks related to financing, obtaining and complying with the terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Third-party developers of generation projects to be owned and operated by the Utility also face these risks. In addition, the Utility may incur costs that it will not be permitted to recover from customers. In addition, the timing and amount of capital spending will directly affect the amount the Utility is able to earn on its authorized rate base, which in turn will affect the ability of PG&E Corporation and the Utility to grow their net income over time. Although recorded capital costs may be trued up in the next GRC, there can be no assurance that the CPUC or the FERC will allow such costs to be included in rate base.

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 an 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 Renewables Portfolio Standard (“RPS”) established under state law requires the Utility to increase its purchases of renewable energy each year 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. The CPUC has established penalties of \$50 per MWh, up to \$25 million per year, for failure to comply with the RPS requirements. The CPUC has encouraged the utilities to pursue the goal to meet 33% of their load with renewable resources by 2020. It is also possible that the RPS requirement may become higher in the future through legislative action or through a ballot initiative.

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. 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 and may result in stranded investment capital, loss of customer growth, and additional barriers to cost recovery. For example, the South San Joaquin Irrigation District (“SSJID”) has sought approval from the local agency formation commission to serve portions of the Utility’s service territory within San Joaquin County. Although SSJID’s plans were rejected by the local agency formation commission in 2006, SSJID has appealed the rejection and has indicated that it intends to pursue its efforts, and has stated that it intends to condemn the Utility’s electric distribution system within SSJID’s boundaries.

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.

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.

Beginning in July 2006, the fixed price provisions of the Utility's power purchase agreements with QFs expired and QFs were allowed to pass to the Utility their cost of the natural gas they purchase as fuel for their generating facilities, increasing the Utility's exposure to natural gas price volatility. The expiration of fixed price provisions in the DWR contracts allocated to the Utility at the end of 2009 will further increase the Utility's exposure to natural gas price risk. Although the Utility attempts to execute CPUC-approved hedging programs to reduce the natural gas price risk, there can be no assurance that these hedging programs will be successful or that the costs of the Utility's hedging programs will 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.

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 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, 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.

In particular, the Utility is undertaking a thorough review of its operating practices and procedures in light of certain recent transformer failures, issues regarding mandated gas leak surveys, and the discovery that some natural gas maintenance records did not accurately reflect field conditions. The Utility has determined that some of its operating procedures need improvement, that other operating procedures are not consistently followed, and that there is a need for improved training and supervision of some operations personnel. The Consumer Protection and Safety Division of the CPUC also is conducting an informal investigation of the Utility's natural gas distribution maintenance practices. Depending on the results of the Utility's review, the Utility may incur costs, not included in forecasts used to set rates in the GRC, to address any identified issues associated with the reliability and safety of the electric and natural gas distribution systems. 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.

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.

Also, 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, there can be no assurance that these efforts will 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. Finally, during 2008, the Utility also will re-negotiate major contracts with two of its labor unions, the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO covering 10,971 employees at December 31, 2007 and the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC covering 1,922 employees at December 31, 2007. The final terms of these new contracts will determine the impact of labor costs on the Utility's future results of operations as the collective bargaining agreements cover 12,929 of the Utility's total 19,785 employees at December 31, 2007. 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. 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. Congress may also enact legislation to limit greenhouse gas emissions. Depending on how the baseline for greenhouse gas emissions level is set, complying with California regulations and potential federal legislation may subject the Utility to significant additional costs. 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 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.

In the event 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 \$201.2 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 to 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. 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. Although the Utility has entered into several purchase agreements for nuclear fuel, with terms ranging from one to thirteen years, there is no assurance the Utility will be able to enter into similar agreements in the future 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. Under current operating procedures, the Utility believes that the existing spent fuel pools have sufficient capacity to enable the Utility to operate Diablo Canyon until approximately 2010 for Unit 1, and 2011 for Unit 2. After receiving a permit from the NRC in March 2004, the Utility began building an on-site dry cask storage facility to store spent fuel through at least 2024. The Utility estimates it could complete the dry cask storage and begin loading spent fuel in 2008. The NRC is still considering issues that were raised by various parties who appealed the NRC's issuance of the permit. (See "Regulatory Matters- Spent Nuclear Fuel Proceeding" above.) The Utility may incur significant additional capital expenditures or experience schedule delays if the NRC decides that the Utility must change the design and construction of the dry cask storage facility. If the Utility is unable to complete the dry cask storage facility, or if operation of the facility is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2. That curtailment or cessation of operations may be continued until such time as additional safe storage for spent fuel is made available. If there is a disruption in production or shutdown of one or both units at this plant, the Utility will need to purchase electricity from more expensive sources.

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 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 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.

Various parties, including the local community, environmental, political, or other groups may participate, or seek to intervene, in regulatory proceedings. In addition, these groups have in the past and may in the future challenge certain aspects of the Utility's nuclear operations through judicial proceedings.

If the CPUC prohibits the Utility from recovering a material amount of its capital expenditures, 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 \$1,000,000 per day per violation) for failure to comply with mandatory electric reliability 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's and the Utility's financial statements reflect various estimates and assumptions, including assumptions about the value of assets held in trust, that could prove to be different.

As described in Note 1 of the Notes to the Consolidated Financial Statements, PG&E Corporation's and the Utility's financial statements reflect management's estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies. In particular, the financial statements reflect the values of the assets held in trust to satisfy the Utility's obligations to decommission its nuclear generation facilities and under pension and other post-retirement benefit plans. The value of these assets is subject to market fluctuations. Also, certain assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, the Utility's funding obligation to the trusts would materially increase.

The outcome of pending and future litigation and legal proceedings, the application of and changes in accounting standards or guidance, tax laws, labor laws, rates or policies, may also adversely affect the Utility's financial condition, results of operations or cash flows.

In the normal course of business, the Utility is named as a party in a number of claims and lawsuits. The Utility may also be the subject of investigative or enforcement proceedings conducted by administrative or regulatory agencies. In accordance with applicable accounting standards, the Utility makes provisions for liabilities when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. If the Utility incurs losses in connection with litigation or other legal, administrative or regulatory proceedings that materially exceeded the provision it made for liabilities, PG&E Corporation's and the Utility's financial condition, results of operations and cash flow would be materially adversely affected.

In addition, there is a risk that changes in accounting or tax rules, standards, guidance, policies, or interpretations, or that changes in management's estimates and assumptions underlying reported amounts of revenues, expenses, assets and liabilities, may result in write-offs, impairments or other charges that could have a material adverse affect on PG&E Corporation's and the Utility's financial condition, results of operations and cash flow.

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

	Year ended December 31,		
	2007	2006	2005
Operating Revenues			
Electric	\$ 9,480	\$ 8,752	\$ 7,927
Natural gas	3,757	3,787	3,776
Total operating revenues	13,237	12,539	11,703
Operating Expenses			
Cost of electricity	3,437	2,922	2,410
Cost of natural gas	2,035	2,097	2,191
Operating and maintenance	3,881	3,703	3,397
Depreciation, amortization, and decommissioning	1,770	1,709	1,735
Total operating expenses	11,123	10,431	9,733
Operating Income	2,114	2,108	1,970
Interest income	164	188	80
Interest expense	(762)	(738)	(583)
Other income (expense), net	29	(13)	(19)
Income Before Income Taxes	1,545	1,545	1,448
Income tax provision	539	554	544
Income From Continuing Operations	1,006	991	904
Discontinued Operations			
Gain on disposal of NEGT (net of income tax benefit of \$13 million in 2005)	-	-	13
Net Income	\$ 1,006	\$ 991	\$ 917
Weighted Average Common Shares Outstanding, Basic	351	346	372
Weighted Average Common Shares Outstanding, Diluted	353	349	378
Earnings Per Common Share from Continuing Operations, Basic	\$ 2.79	\$ 2.78	\$ 2.37
Net Earnings Per Common Share, Basic	\$ 2.79	\$ 2.78	\$ 2.40
Earnings Per Common Share from Continuing Operations, Diluted	\$ 2.78	\$ 2.76	\$ 2.34
Net Earnings Per Common Share, Diluted	\$ 2.78	\$ 2.76	\$ 2.37
Dividends Declared Per Common Share	\$ 1.44	\$ 1.32	\$ 1.23

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 345	\$ 456
Restricted cash	1,297	1,415
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$58 million in 2007 and \$50 million in 2006)	2,349	2,343
Regulatory balancing accounts	771	607
Inventories:		
Gas stored underground and fuel oil	205	181
Materials and supplies	166	149
Income taxes receivable	61	-
Prepaid expenses and other	317	716
Total current assets	5,511	5,867
Property, Plant, and Equipment		
Electric	25,599	24,036
Gas	9,620	9,115
Construction work in progress	1,348	1,047
Other	17	16
Total property, plant, and equipment	36,584	34,214
Accumulated depreciation	(12,928)	(12,429)
Net property, plant, and equipment	23,656	21,785
Other Noncurrent Assets		
Regulatory assets	4,459	4,902
Nuclear decommissioning funds	1,979	1,876
Other	1,043	373
Total other noncurrent assets	7,481	7,151
TOTAL ASSETS	\$ 36,648	\$ 34,803

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2007	2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 519	\$ 759
Long-term debt, classified as current	-	281
Rate reduction bonds, classified as current	-	290
Energy recovery bonds, classified as current	354	340
Accounts payable:		
Trade creditors	1,067	1,075
Disputed claims and customer refunds	1,629	1,709
Regulatory balancing accounts	673	1,030
Other	394	420
Interest payable	697	583
Income taxes payable	-	102
Deferred income taxes	-	148
Other	1,390	1,513
Total current liabilities	6,723	8,250
Noncurrent Liabilities		
Long-term debt	8,171	6,697
Energy recovery bonds	1,582	1,936
Regulatory liabilities	4,448	3,392
Asset retirement obligations	1,579	1,466
Income taxes payable	234	-
Deferred income taxes	3,053	2,840
Deferred tax credits	99	106
Other	1,954	2,053
Total noncurrent liabilities	21,120	18,490
Commitments and Contingencies (Notes 2, 4, 5, 6, 7, 8, 9, 11, 13, 15, and 17)		
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 378,385,151 common and 1,261,125 restricted shares in 2007 and issued 372,803,521 common and 1,377,538 restricted shares in 2006	6,110	5,877
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Reinvested earnings	3,151	2,671
Accumulated other comprehensive income (loss)	10	(19)
Total common shareholders' equity	8,553	7,811
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 36,648	\$ 34,803

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2007	2006	2005
Cash Flows From Operating Activities			
Net income	\$ 1,006	\$ 991	\$ 917
Gain on disposal of NEGТ (net of income tax benefit of \$13 million in 2005)	-	-	(13)
Net income from continuing operations	1,006	991	904
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,895	1,756	1,698
Tax benefit from employee stock plans	-	-	50
Gain on sale of assets	(1)	(11)	-
Deferred income taxes and tax credits, net	55	(285)	(659)
Other changes in noncurrent assets and liabilities	192	151	33
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(6)	130	(245)
Inventories	(41)	32	(60)
Accounts payable	(178)	17	257
Accrued taxes/income taxes receivable	56	124	(207)
Regulatory balancing accounts, net	(567)	329	254
Other current assets	172	(273)	29
Other current liabilities	8	(233)	273
Other	(45)	(14)	82
Net cash provided by operating activities	2,546	2,714	2,409
Cash Flows From Investing Activities			
Capital expenditures	(2,769)	(2,402)	(1,804)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Proceeds from nuclear decommissioning trust sales	830	1,087	2,918
Purchases of nuclear decommissioning trust investments	(933)	(1,244)	(3,008)
Other	-	-	23
Net cash used in investing activities	(2,666)	(2,427)	(1,398)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	850	350	260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of \$1 million in 2007 and \$2 million in 2006	(209)	458	-
Proceeds from issuance of long-term debt, net of discount and issuance costs of \$16 million in 2007 and \$3 million in 2005	1,184	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of \$21 million in 2005	-	-	2,711
Long-term debt matured, redeemed or repurchased	-	-	(1,556)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock with mandatory redemption provisions redeemed	-	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	-	(37)
Common stock issued	175	131	243
Common stock repurchased	-	(114)	(2,188)
Common stock dividends paid	(496)	(456)	(334)
Other	35	3	32
Net cash provided by (used in) financing activities	9	(544)	(1,270)
Net change in cash and cash equivalents	(111)	(257)	(259)
Cash and cash equivalents at January 1	456	713	972

Cash and cash equivalents at December 31	\$	345	\$	456	\$	713
Supplemental disclosures of cash flow information						
Cash paid for:						
Interest (net of amounts capitalized)	\$	514	\$	503	\$	403
Income taxes paid, net		537		736		1,392
Supplemental disclosures of noncash investing and financing activities						
Common stock dividends declared but not yet paid	\$	129	\$	117	\$	115
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)

	<u>Common Stock Shares</u>	<u>Common Stock Amount</u>	<u>Common Stock Held by Subsidiary</u>	<u>Unearned Compensation</u>	<u>Reinvested Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Total Common Share- holders' Equity</u>	<u>Comprehensive Income</u>
Balance at December 31, 2004	418,616,141	\$ 6,518	\$ (718)	\$ (26)	\$ 2,863	\$ (4)	\$ 8,633	
Net income	-	-	-	-	917	-	917	\$ 917
Minimum pension liability adjustment (net of income tax benefit of \$3 million)	-	-	-	-	-	(4)	(4)	(4)
Comprehensive income								<u>\$ 913</u>
Common stock issued	10,264,535	247	-	-	-	-	247	
Common stock repurchased	(61,139,700)	(998)	-	-	(1,190)	-	(2,188)	
Common stock warrants exercised	295,919	-	-	-	-	-	-	
Common restricted stock issued	347,710	13	-	(13)	-	-	-	
Common restricted stock cancelled	(116,103)	(4)	-	4	-	-	-	
Common restricted stock amortization	-	-	-	13	-	-	13	
Common stock dividends declared and paid	-	-	-	-	(334)	-	(334)	
Common stock dividends declared but not yet paid	-	-	-	-	(115)	-	(115)	
Tax benefit from employee stock plans	-	50	-	-	-	-	50	
Other	-	1	-	-	(2)	-	(1)	
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><u>\$ 1,035</u></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	<u>379,646,276</u>	<u>\$ 6,110</u>	<u>\$ (718)</u>	<u>\$ -</u>	<u>\$ 3,151</u>	<u>\$ 10</u>	<u>\$ 8,553</u>

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2007	2006	2005
Operating Revenues			
Electric	\$ 9,481	\$ 8,752	\$ 7,927
Natural gas	3,757	3,787	3,777
Total operating revenues	13,238	12,539	11,704
Operating Expenses			
Cost of electricity	3,437	2,922	2,410
Cost of natural gas	2,035	2,097	2,191
Operating and maintenance	3,872	3,697	3,399
Depreciation, amortization and decommissioning	1,769	1,708	1,734
Total operating expenses	11,113	10,424	9,734
Operating Income	2,125	2,115	1,970
Interest income	150	175	76
Interest expense	(732)	(710)	(554)
Other income, net	52	7	16
Income Before Income Taxes	1,595	1,587	1,508
Income tax provision	571	602	574
Net Income	1,024	985	934
Preferred stock dividend requirement	14	14	16
Income Available for Common Stock	\$ 1,010	\$ 971	\$ 918

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2007	2006
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 141	\$ 70
Restricted cash	1,297	1,415
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$58 million in 2007 and \$50 million in 2006)	2,349	2,343
Related parties	6	6
Regulatory balancing accounts	771	607
Inventories:		
Gas stored underground and fuel oil	205	181
Materials and supplies	166	149
Income taxes receivable	15	20
Prepaid expenses and other	314	714
Total current assets	5,264	5,505
Property, Plant, and Equipment		
Electric	25,599	24,036
Gas	9,620	9,115
Construction work in progress	1,348	1,047
Total property, plant, and equipment	36,567	34,198
Accumulated depreciation	(12,913)	(12,415)
Net property, plant, and equipment	23,654	21,783
Other Noncurrent Assets		
Regulatory assets	4,459	4,902
Nuclear decommissioning funds	1,979	1,876
Related parties receivable	23	25
Other	947	280
Total other noncurrent assets	7,408	7,083
TOTAL ASSETS	\$ 36,326	\$ 34,371

See accompanying Notes to the Consolidated Financial Statements.

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

	Balance at December 31,	
	2007	2006
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 519	\$ 759
Long-term debt, classified as current	-	1
Rate reduction bonds, classified as current	-	290
Energy recovery bonds, classified as current	354	340
Accounts payable:		
Trade creditors	1,067	1,075
Disputed claims and customer refunds	1,629	1,709
Related parties	28	40
Regulatory balancing accounts	673	1,030
Other	370	402
Interest payable	697	570
Deferred income taxes	4	118
Other	1,216	1,346
Total current liabilities	6,557	7,680
Noncurrent Liabilities		
Long-term debt	7,891	6,697
Energy recovery bonds	1,582	1,936
Regulatory liabilities	4,448	3,392
Asset retirement obligations	1,579	1,466
Income taxes payable	103	-
Deferred income taxes	3,104	2,972
Deferred tax credits	99	106
Other	1,838	1,922
Total noncurrent liabilities	20,644	18,491
Commitments and Contingencies (Notes 2, 4, 5, 6, 7, 8, 9, 11, 13, 15, and 17)		
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 282,916,485 shares in 2007 and issued 279,624,823 shares in 2006	1,415	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	2,220	1,822
Reinvested earnings	5,694	5,213
Accumulated other comprehensive income (loss)	13	(16)
Total shareholders' equity	9,125	8,200
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 36,326	\$ 34,371

See accompanying Notes to the Consolidated Financial Statements.

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

	Year ended December 31,		
	2007	2006	2005
Cash Flows From Operating Activities			
Net income	\$ 1,024	\$ 985	\$ 934
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	1,892	1,755	1,697
Gain on sale of assets	(1)	(11)	-
Deferred income taxes and tax credits, net	43	(287)	(636)
Other changes in noncurrent assets and liabilities	188	116	21
Net effect of changes in operating assets and liabilities:			
Accounts receivable	(6)	128	(245)
Inventories	(41)	34	(60)
Accounts payable	(196)	21	257
Accrued taxes/income taxes receivable	56	28	(150)
Regulatory balancing accounts, net	(567)	329	254
Other current assets	170	(273)	2
Other current liabilities	24	(235)	273
Other	(45)	(13)	19
Net cash provided by operating activities	2,541	2,577	2,366
Cash Flows From Investing Activities			
Capital expenditures	(2,768)	(2,402)	(1,803)
Net proceeds from sale of assets	21	17	39
Decrease in restricted cash	185	115	434
Proceeds from nuclear decommissioning trust sales	830	1,087	2,918
Purchases of nuclear decommissioning trust investments	(933)	(1,244)	(3,008)
Other	-	1	61
Net cash used in investing activities	(2,665)	(2,426)	(1,359)
Cash Flows From Financing Activities			
Borrowings under accounts receivable facility and working capital facility	850	350	260
Repayments under accounts receivable facility and working capital facility	(900)	(310)	(300)
Net issuance (repayments) of commercial paper, net of discount of \$1 million in 2007 and \$2 million in 2006	(209)	458	-
Proceeds from issuance of long-term debt, net of discount and issuance costs of \$16 million in 2007 and \$3 million in 2005	1,184	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of \$21 million in 2005	-	-	2,711
Long-term debt matured, redeemed or repurchased	-	-	(1,554)
Rate reduction bonds matured	(290)	(290)	(290)
Energy recovery bonds matured	(340)	(316)	(140)
Preferred stock dividends paid	(14)	(14)	(16)
Common stock dividends paid	(509)	(460)	(445)
Preferred stock with mandatory redemption provisions redeemed	-	-	(122)
Preferred stock without mandatory redemption provisions redeemed	-	-	(37)
Equity infusion from PG&E Corporation	400	-	-
Common stock repurchased	-	-	(1,910)
Other	23	38	65
Net cash provided by (used in) financing activities	195	(544)	(1,327)
Net change in cash and cash equivalents	71	(393)	(320)
Cash and cash equivalents at January 1	70	463	783

Cash and cash equivalents at December 31	\$	141	\$	70	\$	463
Supplemental disclosures of cash flow information						
Cash paid for:						
Interest (net of amounts capitalized)	\$	474	\$	476	\$	390
Income taxes paid, net		594		897		1,397
Supplemental disclosures of noncash investing and financing activities						
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, 2004	\$ 294	\$ 1,606	\$ 2,041	\$ (475)	\$ 5,667	\$ (3)	\$ 9,130	
Net income	-	-	-	-	934	-	934	\$ 934
Minimum pension liability adjustment (net of income tax benefit of \$4 million)	-	-	-	-	-	(6)	(6)	(6)
Comprehensive income								<u><u>\$ 928</u></u>
Common stock repurchased	-	(208)	(266)	-	(1,436)	-	(1,910)	
Common stock dividend	-	-	-	-	(445)	-	(445)	
Preferred stock redeemed	(36)	-	1	-	(2)	-	(37)	
Preferred stock dividend	-	-	-	-	(16)	-	(16)	
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><u>\$ 988</u></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><u>\$ 1,053</u></u>
Equity infusion	-	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	<u><u>\$ 258</u></u>	<u><u>\$ 1,415</u></u>	<u><u>\$ 2,220</u></u>	<u><u>\$ (475)</u></u>	<u><u>\$ 5,694</u></u>	<u><u>\$ 13</u></u>	<u><u>\$ 9,125</u></u>

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary 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 its accounts and those of its wholly owned and controlled subsidiaries and variable interest entities for which it is subject to 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. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed, the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Disputed Claims") and customer refunds, asset retirement obligations ("ARO"), allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension and other employee benefit plan liabilities, severance costs, fair value accounting under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), income tax-related assets and liabilities, accruals for legal matters, the fair value of financial instruments, and the Utility's assessment of impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not be recoverable. A change in management's estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. As these estimates and assumptions involve judgments involving a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ from these estimates. PG&E Corporation's and the Utility's Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial position and results of operations for the periods presented.

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.

PG&E Corporation and the Utility each had three account balances that were each greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2007.

Restricted Cash

Restricted cash consists primarily of the Utility's cash held in escrow pending the resolution of the remaining Disputed Claims (see further discussion in Note 15). The Utility also provides deposits 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 collectibility. If circumstances require changes in the

Utility's assumptions, 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 gas stored underground. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Gas stored underground represents purchases that are injected into inventory and then expensed at average cost when withdrawn and distributed to customers.

Property, Plant, and Equipment

Property, plant, and equipment are reported at their original cost. Original cost includes:

- Labor and materials;
- Construction overhead; and
- Allowance for funds used during construction ("AFUDC").

AFUDC

Allowance for funds used during construction ("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. PG&E Corporation and the Utility recorded AFUDC of approximately \$64 million and \$32 million related to equity and debt, respectively, during 2007, \$47 million and \$20 million related to equity and debt, respectively, during 2006, and \$37 million and \$14 million related to equity and debt, respectively, during 2005.

Depreciation

The Utility's composite depreciation rate was 3.28% in 2007, 3.09% in 2006, and 3.28% in 2005.

(in millions)	Gross Plant as of December 31,	
	2007	Estimated Useful Lives
Electricity generating facilities	\$ 2,198	4 to 37 years
Electricity distribution facilities	16,116	16 to 58 years
Electricity transmission	4,675	40 to 70 years
Natural gas distribution facilities	5,218	24 to 52 years
Natural gas transportation	3,141	25 to 45 years
Natural gas storage	47	25 to 48 years
Other	3,824	5 to 43 years
Total	<u>\$ 35,219</u>	

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.

PG&E Corporation and the Utility charge the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service in accordance with 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 includes 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 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. Capitalized software costs totaled \$533 million at December 31, 2007 and \$237 million at December 31, 2006, net of accumulated amortization of approximately \$207 million at December 31, 2007 and \$197 million at December 31, 2006. The increase in capitalized software costs from 2006 to 2007 was primarily due to expenses related to software development for the SmartMeter™ program as well as information system upgrades of several processes and tools used to design, estimate, and schedule work. 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 Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account 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 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 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 \$97 million at December 31, 2007 and \$73 million at December 31, 2006. The accumulated amortization was approximately \$32 million at December 31, 2007 and \$28 million at December 31, 2006.

The Utility's amortization expense related to intangible assets was approximately \$3 million in 2007, 2006, and 2005. The estimated annual amortization expense based on the December 31, 2007 intangible asset balance for the Utility's intangible assets for 2008 through 2012 is approximately \$3 million each year. Intangible assets are recorded to Other Noncurrent Assets 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 nature of power purchase agreements is such that 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, and the contract price for power is correlated with the plant's variable costs of production. In 2007, the Utility entered into a 25-year agreement to purchase as-available electric generation output from a new 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 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 will not consolidate 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, 2007. Future payments to this facility are expected to be recoverable through customer rates.

Impairment of Long-Lived Assets

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144, "Accounting for the Impairment of Long Lived Assets" ("SFAS No. 144"). In accordance with SFAS No. 144, PG&E Corporation and the Utility

evaluate the carrying amounts of long-lived assets for impairment whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets. No significant impairments were recorded in 2007, 2006, and 2005.

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 identified its nuclear generation and certain fossil fuel generation facilities as having ARO under SFAS No. 143. In accordance with FIN 47, the Utility has 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, 2005	\$	1,587
Revision in estimated cash flows		(204)
Accretion		98
Liabilities settled		(15)
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

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 asset retirement obligation 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, communication 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.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. The fair value may be significantly different than the carrying amount of financial instruments that are recorded at historical amounts.

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, 2007 and 2006.
- The fair values of the Utility's fixed rate senior notes, fixed rate pollution control bond loan agreements, and PG&E Energy Recovery Funding LLC's ("PERF") energy recovery bonds ("ERBs") were based on quoted market prices obtained from the Bloomberg financial information system at December 31, 2007.
- The estimated fair value of PG&E Corporation's 9.50% Convertible Subordinated debt was determined by considering the prices of securities displayed as of the close of business on December 31, 2007 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,			
	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt (Note 4):				
PG&E Corporation	\$ 280	\$ 849	\$ 280	\$ 937
Utility	6,823	6,701	5,629	5,616
Rate reduction bonds (Note 5) ⁽¹⁾	-	-	290	292
Energy recovery bonds (Note 6)	1,936	1,928	2,276	2,239

⁽¹⁾ Rate Reduction Bonds matured on December 26, 2007. (See "Note 5: Rate Reduction Bonds" below.)

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 \$269 million and \$295 million at December 31, 2007 and 2006, respectively. The Utility's amortization expense related to this loss was approximately \$26 million in 2007, \$27 million in 2006, and \$32 million in 2005. 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):

	Hedging Transactions in Accordance with SFAS No. 133	Minimum Pension Liability Adjustment	Adoption of SFAS No. 158	Employee Benefit Plan Adjustment in Accordance with SFAS No. 158	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2004	<u>\$ (1)</u>	<u>\$ (4)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 1</u>	<u>\$ (4)</u>
Period change in:						
Minimum pension liability adjustment (net of income tax benefit of \$3 million)	-	(4)	-	-	-	(4)

Other	1	-	-	-	(1)	-
Balance at December 31, 2005	<u>-</u>	<u>(8)</u>	<u>-</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>-</u>	<u>(19)</u>	<u>-</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>\$ -</u>	<u>\$ (19)</u>	<u>\$ 29</u>	<u>\$ -</u>	<u>\$ 10</u>

⁽¹⁾ The Utility recorded approximately \$109 million in 2007 and \$574 million in 2006, pre-tax, as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71. The Utility recorded approximately \$44 million, pre-tax, as an addition to the existing pension regulatory liability in accordance with SFAS No. 71.

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

Electricity revenues, which are comprised of revenue from generation, transmission and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. The "bundled" electricity rate also includes the rate component set by the FERC for electric transmission services. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. 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, 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 in its Consolidated Statements of Income.

Earnings Per Share

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted earnings per common share ("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 the 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 to have been issued upon exercise and the number of shares assumed to have been purchased, is included in weighted average common shares outstanding for the purpose of calculating diluted EPS.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. 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.

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 arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Share-Based Payment

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of SFAS No. 123R, "Share-Based Payment" ("SFAS No. 123R"), using the modified prospective application method which requires that compensation cost be recognized for all share-based payment awards, including unvested stock options, based on the grant-date fair value. SFAS No. 123R requires that an estimate of future forfeitures be made and that compensation cost be recognized only for share-based payment awards that are expected to vest. Prior to January 1, 2006, PG&E Corporation and the Utility accounted for share-based payment awards, such as stock options, restricted stock and other share-based incentive awards, under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("Opinion 25") as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Under the provisions of Opinion 25, PG&E Corporation and the Utility did not recognize compensation cost for stock options for periods prior to January 1, 2006 because the exercise prices of all stock options were equal to the market value of the underlying common stock on the date of grant of the options.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility expensed share-based awards over the stated vesting period regardless of terms that accelerate vesting upon retirement. Subsequent to the adoption of SFAS No. 123R, PG&E Corporation and the Utility recognize compensation expense for all awards over the shorter of the stated vesting period or the requisite service period. If awards granted prior to adopting SFAS No. 123R were expensed over the requisite service period instead of the stated vesting period, there would have been an immaterial impact on the Consolidated Financial Statements of PG&E Corporation and the Utility for 2006.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility presented all tax benefits from share-based payment awards as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123R requires that cash flows from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those awards (excess tax benefits) be classified as financing cash flows.

The tables below show the effect on PG&E Corporation's net income and EPS if PG&E Corporation and the Utility had elected to account for stock-based compensation using the fair-value method under SFAS No. 123 based on the valuation assumptions disclosed in Note 14, for the year ended December 31, 2005:

	Year ended December 31, 2005
(in millions, except per share amounts)	
Net earnings:	
As reported	\$ 917
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(12)
Pro forma	<u>\$ 905</u>
Basic earnings per share:	
As reported	\$ 2.40
Pro forma	2.37
Diluted earnings per share:	
As reported	2.37

If compensation expense had been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings would have been as follows:

	Year ended December 31, 2005
(in millions)	
Net earnings:	
As reported	\$ 918
Deduct: Incremental stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(7)
Pro forma	\$ 911

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. 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. Derivative instruments are presented in other current and noncurrent assets or other current and noncurrent liabilities unless they meet certain exemptions as discussed below.

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. 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, 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. A hedged item is recognized in earnings when it matures or is exercised. 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.

Net realized and unrealized gains or losses on derivative instruments are included in various items in PG&E Corporation's and the Utility's Consolidated Statements of Income, including Cost of Electricity and Cost of Natural Gas. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows in PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of derivative instruments is estimated using 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. 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 12 of the Notes to the Consolidated Financial Statements.

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

Accounting for Uncertainty in Income Taxes

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"). FIN 48 clarifies the accounting for uncertainty in income taxes. FIN 48 prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities based on the merits of the position. If this threshold is met, the second step is to measure the tax position in PG&E Corporation's and the Utility's Consolidated Balance Sheets by using the largest amount of benefit that is greater than 50% likely of being realized upon ultimate 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 effects of adopting FIN 48 were as follows:

	<u>PG&E Corporation</u>	<u>Utility</u>
(in millions)		
At January 1, 2007		
Cumulative effect of adoption – decrease to Beginning Reinvested Earnings	\$ 18	\$ 20

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	<u>PG&E Corporation</u>	<u>Utility</u>
(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	<u>\$ 209</u>	<u>\$ 94</u>

The component of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2007 for PG&E Corporation and the Utility is \$110 million and \$63 million, respectively.

Interest expense was calculated and included in the potential liability for uncertain tax positions for the twelve months ended December 31, 2007. Interest expense was classified as income tax expense in the Consolidated Statements of Income as follows:

	<u>PG&E Corporation</u>	<u>Utility</u>
(in millions)		
For The Twelve Months Ended December 31, 2007		
Increase in interest expense accrued on unrecognized tax benefits	\$ 7	\$ 2

PG&E Corporation and the Utility believe that it is reasonably possible that the total amount of unrecognized tax benefits could decrease by up to \$10 million in the next 12 months as a result of a potential settlement of the 2001-2002 Internal Revenue Service ("IRS") audit.

For a description of tax years that remain subject to examination, see "Taxation Matters" in Note 11 below.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

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 defines fair value measurements and implements a hierarchical disclosure.

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 now 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 which gives precedence to fair value measurements calculated using observable inputs to 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."

Level 2: "Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly."

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.

SFAS No. 157 requires entities to disclose financial fair-valued instruments according to the above hierarchy in each reporting period after implementation. The standard deferred the disclosure of the hierarchy for certain non-financial instruments to fiscal years beginning after November 15, 2008.

SFAS No. 157 should be applied prospectively except if certain criteria are met. Congestion Revenue Rights ("CRRs") held by the Utility meet the criteria and will be adjusted upon adoption to comply with SFAS No. 157 requirements. CRRs allow market participants, including load serving entities, to hedge the financial risk of California Independent System Operator ("CAISO") imposed congestion charges in the Market Redesign and Technology Upgrade ("MRTU") day-ahead market. PG&E Corporation and the Utility are still evaluating the impact of the adjustment to price risk management assets and regulatory liabilities on their Consolidated Balance Sheets. The costs associated with procurement of CRRs are currently being recovered in rates or are probable of recovery in future rates; therefore, the adoption of SFAS No. 157 will not have an impact on earnings.

Fair Value Option

In February 2007, the FASB issued 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 asset and liabilities at fair value, with changes in fair value recognized in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility do not expect the adoption of SFAS No. 159 to materially impact the financial statements.

Amendment of FASB Interpretation No. 39

In April 2007, the FASB issued FASB Staff Position on Interpretation 39, "Amendment of FASB Interpretation No. 39" ("FIN 39-1"). Under FIN 39-1, a reporting entity is permitted to offset the fair value amounts recognized for 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. FIN 39-1 is effective for fiscal years beginning after November 15, 2007. PG&E Corporation and the Utility are currently evaluating the impact of FIN 39-1.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

As discussed in Note 2, PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. Long-term regulatory assets are comprised of the following:

(in millions)	Balance at December 31,	
	2007	2006
Energy recovery bond regulatory asset	\$ 1,833	\$ 2,170
Utility retained generation regulatory assets	947	1,018
Regulatory assets for deferred income tax	732	599
Environmental compliance costs	328	303
Unamortized loss, net of gain, on reacquired debt	269	295
Regulatory assets associated with plan of reorganization	122	147
Contract termination costs	96	120
Scheduling coordinator costs	90	111
Other	42	139
Total regulatory assets	<u>\$ 4,459</u>	<u>\$ 4,902</u>

The energy recovery bond (“ERB”) regulatory asset 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 proceeding under Chapter 11 of the U.S. Bankruptcy Code (the “Chapter 11 Settlement Agreement”). During 2007, the Utility recorded amortization of the ERB regulatory asset of approximately \$337 million. The Utility expects to fully recover this asset by the end of 2012.

As a result of the Chapter 11 Settlement Agreement, the Utility recognized a one-time non-cash gain of \$1.2 billion in 2004 for regulatory assets related to the recovery of previously incurred costs associated with retained generation facilities. The individual components of these regulatory assets are amortized over their respective lives, with a weighted average life of approximately 16 years. During 2007, the Utility recorded amortization of the Utility’s retained generation regulatory assets of approximately \$71 million.

The regulatory assets for deferred income tax represent deferred income tax benefits 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 40 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 periods ranging from 1 to 30 years.

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 periods ranging from 1 to 19 years.

Regulatory assets associated with the Utility’s Chapter 11 Settlement Agreement include costs incurred in financing the Utility’s 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 periods ranging from 5 to 30 years.

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 until the end of September 2014, the power purchase agreement’s original termination date.

The regulatory asset related to scheduling coordinator (“SC”) costs represents costs that the Utility incurred beginning in 1998 in its capacity as an SC for its then existing wholesale transmission customers. The Utility expects to fully recover the SC costs by 2009.

Finally, as of December 31, 2007, “Other” is primarily related to timing differences between the recognition of ARO in accordance with GAAP and the amounts recognized for ratemaking purposes. At December 31, 2006, “Other” is primarily related to price risk management contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivative instruments are recovered or refunded in regulated rates charged to customers.

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

As of December 31, 2007, the Utility had current regulatory assets of approximately \$131 million, consisting primarily of price risk management regulatory assets with terms of less than one year. Price risk management regulatory assets consist of contracts to procure electricity and natural gas designed to reduce commodity price risks that are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivative instruments are recovered or refunded through regulated rates. At December 31, 2006, the amount of current regulatory assets was approximately \$434 million, consisting primarily of the current portion of the rate reduction bond (“RRB”) regulatory asset and price risk management regulatory assets. The RRB regulatory asset represents electric industry restructuring costs, which the Utility fully recovered in 2007. Current regulatory assets are included in Prepaid Expenses and Other in the Consolidated Balance Sheets.

Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
	2007	2006
(in millions)		
Cost of removal obligation	\$ 2,568	\$ 2,340
Asset retirement costs	573	608
Public purpose programs	264	169
California Solar Initiative	159	-
Price risk management	124	37
Employee benefit plans	578	23
Other	182	215
Total regulatory liabilities	<u>\$ 4,448</u>	<u>\$ 3,392</u>

Cost of removal liabilities represent revenues collected for asset removal costs that the Utility expects to incur in the future.

Asset retirement costs represent timing differences between the recognition of ARO in accordance with GAAP and the amounts recognized for ratemaking purposes.

Public purpose program liabilities represent revenues designated for public purpose programs costs that are expected to be incurred in the future.

California Solar Initiative liabilities represent revenues designated for public purpose program costs that are expected to be incurred in the future. These revenues will be used by the Utility to promote the use of solar energy in residential homes, and commercial, industrial, and agricultural properties.

Price risk management liabilities consist of contracts to procure electricity and natural gas with terms in excess of one year designed to reduce commodity price risks that are accounted for as derivative instruments under SFAS No. 133. Changes in the fair value of derivative instruments are deferred and recorded in regulatory accounts because they are recovered or refunded through regulated rates.

Employee benefit plan expenses represent the cumulative differences between amounts recognized in accordance with GAAP and amounts recognized for ratemaking purposes, which also includes amounts that otherwise would be recorded to accumulated other comprehensive income in accordance with SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans". These balances will be charged against expense to the extent that future

expenses exceed amounts recoverable for regulatory purposes.

Finally, as of December 31, 2007, “Other” regulatory liabilities are primarily related to amounts received from insurance companies to pay for hazardous substance remediation costs and future customer benefits associated with the Gateway Generating Station (“Gateway”). The liability for hazardous substance insurance recoveries is refunded to customers as a reduction to rates until they are fully reimbursed for total covered hazardous substance costs that they have paid to date. Gateway was acquired as part of a settlement with Mirant Corporation and the associated liability will be amortized over 30 years beginning in March 2009.

Current Regulatory Liabilities

As of December 31, 2007, the Utility had current regulatory liabilities of approximately \$280 million, 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. At December 31, 2006, the Utility had current regulatory liabilities of \$309 million, primarily comprised of electric transmission wheeling revenue refunds and the RRB regulatory liability. The RRB regulatory liability represents over-collections associated with the RRB financing that the Utility will return to customers in the future. Current regulatory liabilities are included in Current Liabilities - Other in the Consolidated Balance Sheets.

Regulatory Balancing Accounts

The Utility uses regulatory balancing accounts as a mechanism to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. This approval eliminates the earnings impact from any revenue variances from adopted forecast levels. 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. The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities.

Regulatory Balancing Account Assets

	Balance at December 31,	
	2007	2006
(in millions)		
Electricity revenue and cost balancing accounts	\$ 678	\$ 501
Natural gas revenue and cost balancing accounts	93	106
Total	\$ 771	\$ 607

Regulatory Balancing Account Liabilities

	Balance at December 31,	
	2007	2006
(in millions)		
Electricity revenue and cost balancing accounts	\$ 618	\$ 951
Natural gas revenue and cost balancing accounts	55	79
Total	\$ 673	\$ 1,030

During 2007, the under-collection in the Utility's electricity revenue and cost balancing account assets increased from 2006 mainly due to higher procurement costs associated with replacement power, as a result of lower hydroelectric production. The under-collection was further increased due to CPUC authorized rate reductions intended to reduce over-collections in the electric revenue and cost balancing account liabilities from 2006.

NOTE 4: DEBT

Long-Term Debt

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

	December 31,	
	2007	2006
(in millions)		
PG&E Corporation		
Convertible subordinated notes, 9.50%, due 2010	\$ 280	\$ 280
Less: current portion	-	(280)
	<u>280</u>	<u>-</u>
Utility		
Senior notes:		
3.60% to 6.05% bonds, due 2009-2037	6,300	5,100
Unamortized discount	(22)	(16)
Total senior notes	<u>6,278</u>	<u>5,084</u>
Pollution control bond loan agreements, variable rates ⁽¹⁾ , due 2026 ⁽²⁾	614	614
Pollution control bond loan agreement, 5.35%, due 2016	200	200
Pollution control bond loan agreements, 4.75%, due 2023	345	345
Pollution control bond loan agreements, variable rates ⁽³⁾ , due 2016-2026	454	454
Other	-	1
Less: current portion	-	(1)
Long-term debt, net of current portion	<u>7,891</u>	<u>6,697</u>
Total consolidated long-term debt, net of current portion	<u><u>\$ 8,171</u></u>	<u><u>\$ 6,697</u></u>

⁽¹⁾ At December 31, 2007, interest rates on these loans ranged from 3.45% to 3.73%.

⁽²⁾ These bonds are supported by \$620 million of letters of credit which expire on February 24, 2012. Although the stated maturity date is 2026, the bonds will remain outstanding only if the Utility extends or replaces the letters of credit.

⁽³⁾ At December 31, 2007, interest rates on these loans ranged from 3.75% to 5.75%.

PG&E Corporation

Convertible Subordinated Notes

At December 31, 2007, PG&E Corporation had outstanding approximately \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. Interest is payable semi-annually in arrears on June 30 and December 31. 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 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 2007, PG&E Corporation paid approximately \$26 million of "pass-through dividends" to the holders of Convertible Subordinated Notes. On January 15, 2008, PG&E Corporation paid approximately \$7 million of "pass-through dividends." Since no holders of the Convertible Subordinated Notes exercised the one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, PG&E Corporation reclassified the Convertible Subordinated Notes as a noncurrent liability (in Noncurrent Liabilities - Long-Term Debt) in the Consolidated Balance Sheets effective as of that date.

In accordance with SFAS No. 133, the dividend participation rights component of the Convertible Subordinated Notes is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Consolidated Financial Statements. Dividend participation rights are recognized as operating cash flows 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, Net). At December 31, 2007 and December 31, 2006, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately \$62 million and \$79 million, respectively, of which \$25 million and \$23 million, respectively, was classified as a current liability (in Current Liabilities - Other) and \$37 million and \$56 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other) in the accompanying Consolidated Balance Sheets.

Utility

Senior Notes

In March 2007, the Utility issued \$700 million principal amount of 5.80% Senior Notes due March 1, 2037. The Utility received proceeds of \$690 million from the offering, net of a \$4 million discount and \$6 million in issuance costs. In December 2007, the Utility issued \$500 million principal amount of 5.625% Senior Notes due November 30, 2017. The Utility received proceeds of \$494 million from the offering, net of a \$3 million discount and \$3 million in issuance costs. The proceeds from the sale of the Senior Notes were used for capital expenditures and working capital purposes.

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 sale 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 issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At December 31, 2007, pollution control bonds in the aggregate principal amount of \$1.6 billion were outstanding. Under the pollution control bond loan agreements, 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.

All of the pollution control bonds financed or refinanced pollution control facilities at the Utility's Geysers geothermal power plant ("Geysers Project"), or at the Utility's Diablo Canyon Power Plant ("Diablo Canyon"). In 1999, the Utility sold the Geysers Project to Geysers Power Company LLC, a subsidiary of Calpine Corporation. The Geysers Project purchase and sale agreements state that Geysers Power Company LLC will use the facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Internal Revenue Code and associated regulations ("Code").

On February 3, 2006, Geysers Power Company LLC filed a petition for relief under Chapter 11 of the Bankruptcy Code with the United States Bankruptcy Court for the Northern District of California (the "Bankruptcy Court"). On December 19, 2007, the Bankruptcy Court entered an order confirming the Plan of Reorganization (the "Plan") filed by Calpine Corporation and related debtors, including Geysers Power Company LLC. The Plan became effective on January 31, 2008. Pursuant to the Plan, Geysers Power Company LLC assumed the purchase and sale agreements. The Utility believes that the Geysers Project will continue to meet the use requirements of the Code.

In order to enhance the credit ratings of these pollution control bonds, the Utility has obtained credit support from banks and insurance companies such that, in the event that the Utility does not pay debt servicing costs, the banks or insurance companies will pay the debt servicing costs. The following table summarizes these credit supports:

Utility Facility ⁽¹⁾ (in millions)	Series	Termination Date	At December 31, 2007 Commitment
Pollution control bond - bank reimbursement agreements	96 C, E, F, 97 B	February 2012	\$ 620
Pollution control bond - bond insurance reimbursement agreements	96 A	December 2016 ⁽²⁾	200
Pollution control bond - bond insurance reimbursement agreements	2004 A - D	December 2023 ⁽²⁾	345
Pollution control bond - bond insurance reimbursement agreements	2005 A - G	2016 - 2026 ⁽²⁾	454
Total credit support			\$ 1,619

⁽¹⁾ Off-balance sheet commitments.

⁽²⁾ Principal and debt service insured by bond insurance companies.

Generally, under the loan agreements related to the Utility's pollution control bonds, the Utility, among other things, agrees to pay principal, interest or any premium on the bonds to the trustee in accordance with the relevant indentures, maintain and repair the underlying projects financed by such bonds, and not 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" within the meaning of Section 142(a) of the Code.

In 2005, the Utility purchased a financial guaranty insurance policy to insure the regularly scheduled payment of principal and interest on \$454 million of pollution control bonds series 2005 A-G ("PC2005 bonds") issued by the California Infrastructure and Economic Development Bank. In January 2008, the insurer's credit rating was downgraded and/or put on review for possible downgrade by several credit agencies. This has resulted in increases in interest rates for the PC2005 bonds, which rates are currently set at auction every 7 or 35 days. To minimize this interest rate exposure, the Utility intends to exercise its right to purchase the bonds in lieu of redemption and remarket the bonds when market conditions are more favorable. The purchase of the PC2005 bonds is expected to be financed through issuance of long-term debt.

Repayment Schedule

At December 31, 2007, PG&E Corporation's and the Utility's combined aggregate principal repayment amounts of long-term debt are reflected in the table below:

(in millions, except interest rates)	2008	2009	2010	2011	2012	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%	-	4.20%	-	5.66%	5.37%
Fixed rate obligations	-	\$ 600	-	\$ 500	-	\$ 5,745	\$ 6,845
Variable interest rate as of December 31, 2007	-	-	-	-	3.56%	4.47%	3.95%
Variable rate obligations	-	-	-	-	\$ 614 ⁽¹⁾	\$ 454	\$ 1,068
Total consolidated long-term debt	-	\$ 600	\$ 280	\$ 500	\$ 614	\$ 6,199	\$ 8,193

⁽¹⁾ 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, 2007:

(in millions)			At December 31, 2007				
Authorized Borrower	Facility	Termination Date	Facility Limit	Letters of Credit Outstanding	Cash Borrowings	Commercial Paper Backup	Availability
PG&E Corporation	Senior credit facility	February 2012	\$ 200 ⁽¹⁾	\$ -	\$ -	\$ -	\$ 200
Utility	Working capital facility	February 2012	2,000 ⁽²⁾	165	250	270	1,315
Total credit facilities			<u>\$ 2,200</u>	<u>\$ 165</u>	<u>\$ 250</u>	<u>\$ 270</u>	<u>\$ 1,515</u>

⁽¹⁾ Includes \$50 million sublimit for letters of credit and \$100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

⁽²⁾ Includes a \$950 million sublimit for letters of credit and \$100 million sublimit for swingline loans, which are made available on a same-day basis and repayable in full within 30 days.

PG&E Corporation

Senior Credit Facility

PG&E Corporation has a \$200 million revolving senior unsecured credit facility ("senior credit facility") with a syndicate of lenders that expires on February 26, 2012. Borrowings under the senior 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 senior 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 senior 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").

The senior 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 working capital facility, discussed below. In addition, the senior 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, 2007, PG&E Corporation had no outstanding borrowings or letters of credit under the senior credit facility.

Utility

In the ordinary course of the Utility's construction activities, contractors who work on and provide materials to projects may have certain statutory liens on such projects, which are released as construction progresses and payments are made for their work or materials.

Working Capital Facility

On February 26, 2007, the Utility increased its revolving credit facility ("working capital facility") with a syndicate of lenders by \$650 million to \$2.0 billion and extended the facility to February 26, 2012. The working capital 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 working capital facility also requires that the Utility maintain a debt to capitalization ratio of at most 65% as of the end of each fiscal quarter. There were no material changes to the terms, fees, interest rates, or covenants related to the working capital facility as a result of the February 2007 amendment.

Letters of credit issued under the working capital facility are used primarily to provide credit enhancements to counterparties for natural gas and energy procurement transactions. At December 31, 2007, there were approximately \$165 million of letters of credit and \$250 million of borrowings outstanding under the working capital facility. In addition, the Utility treats the amount of its outstanding commercial paper as a reduction to the amount available under its working capital facility to provide liquidity support for outstanding commercial paper, as discussed below.

Accounts Receivable Facility

On February 26, 2007, in connection with the amendment of the working capital facility described above, the Utility terminated its \$650 million accounts receivable facility that was scheduled to expire on March 5, 2007. There were no loans outstanding under the Utility's accounts receivable facility at the time of termination.

Commercial Paper Program

On June 28, 2007, the Utility increased its borrowing capacity under the commercial paper program from \$1.0 billion to \$1.75 billion. Commercial paper borrowings are used primarily to cover fluctuations in cash flow requirements. Liquidity support for these borrowings is provided by available capacity under the working capital 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. At December 31, 2007, the Utility had \$270 million of commercial paper outstanding, including amortization of a \$1 million discount, at an average yield of approximately 5.6%. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

NOTE 5: 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 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. At December 31, 2006, the total amount of RRB principal outstanding was \$290 million. The RRBs were paid in full when they matured on December 26, 2007 and there are no future principal or interest payments.

NOTE 6: ENERGY RECOVERY BONDS

In furtherance of the Chapter 11 Settlement Agreement, PERF, a wholly owned consolidated subsidiary of the Utility, issued two separate series of ERBs in the aggregate amount of \$2.7 billion in 2005 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 related to the first series of ERBs.

The total amount of ERB principal outstanding was \$1.9 billion at December 31, 2007 and \$2.3 billion at December 31, 2006. The scheduled principal repayments for ERBs are reflected in the table below:

(in millions)	2008	2009	2010	2011	2012	Total
Utility						
Average fixed interest rate	4.19%	4.36%	4.49%	4.59%	4.66%	4.47%
Energy recovery bonds	\$ 354	\$ 370	\$ 386	\$ 404	\$ 422	\$ 1,936

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.

NOTE 7: DISCONTINUED OPERATIONS

National Energy & Gas Transmission, Inc. ("NEGT") was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. NEGТ filed a voluntary petition for relief under Chapter 11 on July 8, 2003. On October 29, 2004, NEGТ's plan of reorganization became effective, at which time NEGТ emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGТ was cancelled. On the effective date, PG&E Corporation recorded a net of tax gain on disposal of NEGТ of \$684 million. Based on the additional information received from NEGТ in 2005 regarding PG&E Corporation's 2004 and 2003 federal income tax returns, PG&E Corporation recorded \$13 million in income from discontinued operations.

At December 31, 2007 and 2006, PG&E Corporation's Consolidated Balance Sheets included the following assets and liabilities related to NEGТ:

(in millions)	2007	2006
Current Assets		
Income taxes receivable	\$ 33	\$ -
Current Liabilities		
Income taxes payable	-	89
Other	11	11
Noncurrent Liabilities		
Income taxes payable	74	-
Deferred income taxes	34	-
Other	14	15

Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. PG&E Corporation ceased including NEGТ and its subsidiaries in its consolidated

income tax returns beginning October 29, 2004.

NOTE 8: COMMON STOCK

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock, of which 379,646,276 shares were issued and outstanding at December 31, 2007 and 374,181,059 shares were issued and outstanding at December 31, 2006. Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, holds 24,665,500 of the outstanding shares.

Of the 379,646,276 shares issued and outstanding at December 31, 2007, 1,261,125 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 4,920,648 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 ("DRSPP"). (See Note 14 for further discussion.)

Stock Repurchases

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement ("ASR") with Goldman Sachs & Co., Inc. ("GS&Co."), under which PG&E Corporation repurchased 9,769,600 shares of its outstanding common stock for an aggregate purchase price of approximately \$332 million, including a \$14 million price adjustment paid on February 22, 2005. This adjustment was based on the daily volume weighted average market price ("VWAP") of PG&E Corporation common stock over the term of the arrangement.

In 2005, PG&E Corporation repurchased a total of 61,139,700 shares of its outstanding common stock through two ASRs with GS&Co. for an aggregate purchase price of \$2.2 billion, including price adjustments based on the VWAP and other amounts. In 2006, PG&E Corporation paid GS&Co. \$114 million in additional payments (net of amounts payable by GS&Co. to PG&E Corporation) to satisfy obligations under the last of these ASRs entered into in November 2005. PG&E Corporation's payments reduced common shareholders' equity.

To reflect the potential dilution that existed while the obligations related to the ASRs were outstanding, PG&E Corporation treated approximately one million and two million additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for 2006 and 2005, respectively (see Note 10 for further discussion). PG&E Corporation has no remaining obligation under the November 2005 ASR as of December 31, 2007.

Utility

The Utility is authorized to issue 800 million shares of its \$5 par value common stock, of which 282,916,485 shares were issued and outstanding as of December 31, 2007 and 279,624,823 shares were issued and outstanding as of December 31, 2006. PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold 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

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without Bankruptcy Court approval and certain covenants in the indenture related to senior secured notes of PG&E Corporation during that period restricted the circumstances under which such a dividend could be declared or paid. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends. The Utility reinstated the payment of a regular quarterly common stock dividend to PG&E Corporation in January 2005, upon the achievement of the 52% equity ratio targeted in the Chapter 11 Settlement Agreement.

During 2005, the Utility paid common stock dividends of \$476 million. Approximately \$445 million of common stock dividends were paid to PG&E Corporation and the remaining amount was paid to PG&E Holdings, LLC. On April 15, July 15, and October 15, 2005, PG&E Corporation paid quarterly common stock dividends of \$0.30 per share, totaling approximately \$356 million, including approximately \$22 million 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. On January 16, April 15,

July 15, and October 15, 2006, PG&E Corporation paid quarterly common stock dividends of \$0.33 per share, totaling \$489 million, including approximately \$33 million to Elm Power Corporation.

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. PG&E Holdings, LLC held approximately 7% of the Utility's common stock.

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. The above dividend payments totaled \$529 million, including approximately \$35 million of common stock dividends paid to Elm Power Corporation. Elm Power Corporation held approximately 6% of PG&E Corporation's common stock.

On December 19, 2007, the Board of Directors of PG&E Corporation declared a dividend of \$0.36 per share, totaling approximately \$137 million that was paid on January 15, 2008 to shareholders of record on December 31, 2007.

PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

NOTE 9: 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, 2007 and 2006, 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, 2007 and 2006, 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, 2007, 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 year ended December 31, 2005, the Utility paid approximately \$16 million of dividends on preferred stock without mandatory redemption provisions and approximately \$5 million of dividends on preferred stock with mandatory redemption provisions. During the years ended December 31, 2007 and December 31, 2006, the Utility paid approximately \$14 million of dividends on preferred stock without mandatory redemption provisions. On December 19, 2007, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock totaling approximately \$3 million that was paid on February 15, 2008 to shareholders of record on January 31, 2008. 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.

On June 15, 2005, the Utility's Board of Directors authorized the redemption of all of the outstanding shares of the Utility's 7.04% Redeemable First Preferred Stock totaling approximately \$36 million aggregate par value plus approximately \$1 million related to a \$0.70 per share redemption premium. This issue was fully redeemed on August 31, 2005. In addition to the \$25 per share redemption price, holders of the 7.04% Redeemable First Preferred Stock received an amount equal to all accumulated and unpaid dividends through August 31, 2005 on such shares totaling approximately \$211,000.

NOTE 10: EARNINGS PER 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. SFAS No. 128 requires that proceeds from the exercise of options and warrants are assumed to be used to purchase shares of common stock 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) must be included in the number of weighted average shares of common stock used for the calculation of 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,		
	2007	2006	2005
Net Income	\$ 1,006	\$ 991	\$ 917
Less: distributed earnings to common shareholders	508	460	449
Undistributed earnings	498	531	468
Less: undistributed earnings from discontinued operations	-	-	13
Undistributed earnings from continuing operations	<u>\$ 498</u>	<u>\$ 531</u>	<u>\$ 455</u>
Common shareholders earnings			
<i>Basic</i>			
Distributed earnings to common shareholders	\$ 508	\$ 460	\$ 449
Undistributed earnings allocated to common shareholders - continuing operations	472	503	433
Undistributed earnings allocated to common shareholders - discontinued operations	-	-	12
Total common shareholders earnings, basic	<u>\$ 980</u>	<u>\$ 963</u>	<u>\$ 894</u>
<i>Diluted</i>			
Distributed earnings to common shareholders	\$ 508	\$ 460	\$ 449
Undistributed earnings allocated to common shareholders - continuing operations	473	504	433
Undistributed earnings allocated to common shareholders - discontinued operations	-	-	12
Total common shareholders earnings, diluted	<u>\$ 981</u>	<u>\$ 964</u>	<u>\$ 894</u>
Weighted average common shares outstanding, basic	351	346	372
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, basic	<u>370</u>	<u>365</u>	<u>391</u>
Weighted average common shares outstanding, basic	351	346	372
Employee share-based compensation and accelerated share repurchases ⁽¹⁾	2	3	6
Weighted average common shares outstanding, diluted	<u>353</u>	<u>349</u>	<u>378</u>
9.50% Convertible Subordinated Notes	19	19	19
Weighted average common shares outstanding and participating securities, diluted	<u>372</u>	<u>368</u>	<u>397</u>
Net earnings per common share, basic			
Distributed earnings, basic ⁽²⁾	\$ 1.45	\$ 1.33	\$ 1.21

Undistributed earnings - continuing operations, basic	1.34	1.45	1.16
Undistributed earnings - discontinued operations, basic	-	-	0.03
Total	<u>\$ 2.79</u>	<u>\$ 2.78</u>	<u>\$ 2.40</u>
Net earnings per common share, diluted			
Distributed earnings, diluted	\$ 1.44	\$ 1.32	\$ 1.19
Undistributed earnings - continuing operations, diluted	1.34	1.44	1.15
Undistributed earnings - discontinued operations, diluted	-	-	0.03
Total	<u>\$ 2.78</u>	<u>\$ 2.76</u>	<u>\$ 2.37</u>

⁽¹⁾ Includes approximately one million and two million shares of PG&E Corporation common stock treated as outstanding in connection with accelerated share repurchase agreements (ASRs) for 2006 and 2005, respectively. The remaining shares of approximately two million at December 31, 2006 and four million at December 31, 2005 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. See the section of Note 2 entitled "Earnings Per Share."

⁽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 7,285 and 28,500 shares were excluded from the computation of diluted EPS for 2007 and 2005, 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 11: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2007	2006	2005	2007	2006	2005
(in millions)						
Current:						
Federal	\$ 526	\$ 743	\$ 1,027	\$ 563	\$ 771	\$ 1,048
State	140	201	189	149	210	196
Deferred:						
Federal	(81)	(286)	(574)	(92)	(276)	(572)
State	(40)	(98)	(89)	(43)	(97)	(89)
Tax credits, net	(6)	(6)	(9)	(6)	(6)	(9)
Income tax expense	<u>\$ 539</u>	<u>\$ 554</u>	<u>\$ 544</u>	<u>\$ 571</u>	<u>\$ 602</u>	<u>\$ 574</u>

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
	2007	2006	2007	2006
(in millions)				
Deferred income tax assets:				
Customer advances for construction	\$ 143	\$ 170	\$ 143	\$ 170
Reserve for damages	173	165	173	165
Environmental reserve	172	177	172	177
Compensation	162	131	129	95
Other	289	206	261	166
Total deferred income tax assets	<u>\$ 939</u>	<u>\$ 849</u>	<u>\$ 878</u>	<u>\$ 773</u>
Deferred income tax liabilities:				
Regulatory balancing accounts	\$ 1,219	\$ 1,305	\$ 1,219	\$ 1,305
Property related basis differences	2,290	2,142	2,293	2,142

Income tax regulatory asset	298	243	298	243
Unamortized loss on reacquired debt	110	120	110	120
Other	75	27	66	53
Total deferred income tax liabilities	\$ 3,992	\$ 3,837	\$ 3,986	\$ 3,863
Total net deferred income tax liabilities	\$ 3,053	\$ 2,988	\$ 3,108	\$ 3,090
Classification of net deferred income tax liabilities:				
Included in current liabilities	\$ -	\$ 148	\$ 4	\$ 118
Included in noncurrent liabilities	3,053	2,840	3,104	2,972
Total net deferred income tax liabilities	\$ 3,053	\$ 2,988	\$ 3,108	\$ 3,090

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,					
	2007	2006	2005	2007	2006	2005
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)	4.2	4.3	4.5	4.3	4.6	4.6
Effect of regulatory treatment of fixed asset differences	(3.0)	(1.2)	(0.6)	(2.9)	(1.1)	(0.6)
Tax credits, net	(0.7)	(0.6)	(1.0)	(0.7)	(0.6)	(0.9)
Other, net	(0.6)	(1.6)	(0.3)	0.1	0.1	(0.1)
Effective tax rate	34.9%	35.9%	37.6%	35.8%	38.0%	38.0%

In recent months PG&E Corporation reached settlements on a number of its open tax years with the IRS.

In the first quarter of 2008, PG&E Corporation reached a settlement with the IRS appellate division for tax years 1997-2000. This settlement would not result in material changes to unrecognized tax benefits recognized under FIN 48, and it would resolve all open issues for those years with the exception of reserving the right to file two refund claims. The most significant claim relates to the deferral of gains from power plant sales and income from recovery of transition costs during 1998 and 1999.

In addition, during the first quarter of 2008, PG&E Corporation reached a tentative settlement with the IRS for tax years 2001-2002. The IRS has indicated that it intends to apply aspects of this tentative settlement to resolution of later tax years. That settlement, if finalized, would resolve several significant deductions taken in the 2002 tax return with respect to assets abandoned at NEGT, as well as issues affecting the Utility. However, this settlement would be subject to approval by the Joint Committee on Taxation. Two issues are not part of the audit settlement and will be referred to the IRS appellate division. The most significant of these is a dispute over PG&E Corporation's entitlement to \$104 million in synthetic fuel tax credits.

The IRS also has indicated that it intends to complete its audit examination of tax years 2003-2004 by June 2008. Based on the IRS' proposed adjustments, this audit could be resolved within the next 18 months.

Currently, PG&E Corporation has \$247 million of federal capital loss carry forwards based on tax returns as filed from the disposition of NEGT stock in 2004, which, if not used by December 2009, will expire. The settlement of the 2001-2002 audit together with the completion of the 2003-2004 audit could result in utilization of a significant portion of the federal capital loss carry forwards. However, because the settlement of the 2003-2004 audit remains uncertain, no benefits have been recognized.

The settlement of the 2001-2002 audit and the completion of the 2003-2004 audit could also result in net changes to unrecognized tax benefits currently recorded pursuant to FIN 48 (see Note 2 for further discussion of the impact of adopting FIN 48).

The California Franchise Tax Board is currently auditing PG&E Corporation's 2004 and 2005 combined California income tax returns. To date, no 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, if not used by 2008, will expire. PG&E Corporation believes it has accrued adequate reserves for tax years that are open for California tax purposes.

NOTE 12: DERIVATIVES AND HEDGING ACTIVITIES

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel, and firm electricity transmission rights. Some of these contracts meet the definition of derivative instruments under SFAS No. 133. All derivative instruments, including instruments designated as cash flow hedges, are recorded at fair value and presented as price risk management assets and liabilities on the balance sheet (see table below). Changes in the fair value of derivative instruments are deferred and recorded in regulatory accounts because they are expected to be recovered or refunded through regulated rates. Under the same regulatory accounting treatment, changes in the fair value of cash flow hedges are also recorded in regulatory accounts, rather than being deferred in accumulated other comprehensive income.

On PG&E Corporation's 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 as the right of offset exists, resulting in a net asset or liability as follows:

(in millions)	Derivatives	
	December 31, 2007	December 31, 2006
Current Assets – Prepaid expenses and other	\$ 52	\$ 16
Other Noncurrent Assets – Other	125	37
Current Liabilities – Other	83	192
Noncurrent Liabilities – Other	20	50

Derivative instruments may be designated as cash flow hedges when they hedge variable price risk associated with the purchase of commodities. Cash flow hedges are presented on a net basis by counterparty.

The table below represents the portion of the derivative balances that were designated as cash flow hedges:

(in millions)	Cash Flow Hedges	
	December 31, 2007	December 31, 2006
Current Assets – Prepaid expenses and other ⁽¹⁾	\$ (2)	\$ 3
Other Noncurrent Assets – Other	33	8
Current Liabilities – Other	19	25
Noncurrent Liabilities – Other	3	-

⁽¹⁾ \$2 million of the cash flow hedges in a liability position at December 31, 2007 relate to counterparties for which the total net derivatives position is a current asset.

The Utility also 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 on the Consolidated Balance Sheets. They are recorded and recognized in income using accrual accounting. Therefore, expenses are recognized in cost of electricity and cost of natural gas as incurred.

Net realized gains or losses on derivative instruments are included in various items on PG&E Corporation's and the Utility's Consolidated Statements of Income, including cost of electricity and cost of natural gas. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The dividend participation rights associated with PG&E Corporation's Convertible Subordinated Notes are recorded at fair value in PG&E Corporation's Consolidated Financial Statements in accordance with SFAS No. 133. (See Note 4 above for discussion of the Convertible Subordinated Notes.)

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. In the Utility’s 2005 Nuclear Decommissioning Cost Triennial Proceeding (“NDCTP”), 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.

As presented in the Utility’s NDCTP, the estimated nuclear decommissioning cost for Diablo Canyon Units 1 and 2 and Humboldt Bay Unit 3 is approximately \$2.19 billion in 2007 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 GAAP 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 Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately \$1.3 billion at December 31, 2007 and \$1.2 billion at December 31, 2006. 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 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 in regulatory accounts. (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 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 trust 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. For the non-qualified trust, no more than 60% may be invested in publicly-traded equities, 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.

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to be 5.33% and in the non-qualified trusts to be 4.22%. Trust earnings are included in the nuclear decommissioning trust assets and the corresponding asset retirement costs regulatory liability. 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 2007, the trusts earned approximately \$77 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. At December 31, 2007, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately \$2.0 billion, based on quoted market prices and 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.

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." 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.

In 2007, total unrealized losses on the investments held in the trusts were \$7 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 \$7 million impairment is not other-than-temporary. As a result, an impairment loss was recognized and the Utility recorded a \$7 million reduction to the nuclear decommissioning trusts assets and the asset retirement costs regulatory liability.

The following table provides a summary of the fair value, based on quoted market prices, of the investments held in the Utility's nuclear decommissioning trusts:

	Maturity Date	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Estimated ⁽¹⁾ Fair Value
(in millions)					
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>
Year ended December 31, 2006					
U.S. government and agency issues	2007-2036	\$ 781	\$ 34	\$ (1)	\$ 814
Municipal bonds and other	2007-2049	252	7	(1)	258
Equity securities		347	644	-	991
Total		<u>\$ 1,380</u>	<u>\$ 685</u>	<u>\$ (2)</u>	<u>\$ 2,063</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:

	Year Ended December 31,		
	2007	2006	2005
(in millions)			
Proceeds received from sales of securities	\$ 830	\$ 1,087	\$ 2,918
Gross realized gains on sales of securities held as available-for-sale	61	55	56
Gross realized losses on sales of securities held as available-for-sale	(42)	(29)	(14)

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 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. On January 15, 2008, the NRC decided to hold hearings on whether it provided a complete list of the references upon which it relied to find that there would not be a significant environmental impact and whether it sufficiently addressed the impacts on land and the local economy of a potential terrorist attack. It is expected that the NRC will issue a final decision in the third quarter of 2008.

The Utility expects to complete the dry cask storage facility and begin loading spent fuel in 2008. If the Utility is unable to complete the dry cask storage facility, if operation of the facility is delayed beyond 2010, or if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and continued until such time as additional safe storage for spent fuel is made available.

The Utility and other nuclear power plant owners have sued the DOE for breach of contract. The Utility seeks to recover its costs to develop on-site storage at Diablo Canyon and Humboldt Bay Unit 3. 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. The Utility appealed to the U.S. Court of Appeals for the Federal Circuit seeking to increase the amount of the award and challenged the U.S. Court of Federal Claims' finding that the Utility would have incurred some of the costs for the on-site storage facilities even if the DOE had complied with the contract. A decision on the appeal is expected by the end of 2008. The Utility will seek to recover costs incurred after 2004 in future lawsuits against the DOE. Any 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 this appeal or the amount of any additional awards the Utility may receive. If the U.S. Court of Federal Claims' decision is not overturned or modified on appeal, it is likely that the Utility will be unable to recover all of its future costs for on-site storage facilities from the DOE. However, reasonably incurred costs related to the on-site storage facilities are, in the case of Diablo Canyon, recoverable through rates and, in the case of Humboldt Bay Unit 3, recoverable through its decommissioning trust fund.

NOTE 14: EMPLOYEE COMPENSATION PLANS

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for certain employees and retirees, referred to collectively as pension benefits. PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Internal Revenue 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 Internal Revenue Code limitations. PG&E Corporation and its subsidiaries also provide contributory defined benefit medical plans for certain retired employees and their eligible dependents, and non-contributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). 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 its subsidiaries use a December 31 measurement date for all of their 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 Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. Only the portion of the pension contribution allocated to the gas transmission and storage business is not recoverable in rates. For 2007, the reduction in net income as a result of the Utility not being able to recover this portion in rates was approximately \$3 million, net of tax. A regulatory adjustment is also recorded for the amounts that would otherwise be charged to accumulated other comprehensive income under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" ("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. This recovery mechanism does not allow the Utility to record a regulatory asset for the SFAS No. 158 charge to accumulated other comprehensive income related to other benefits. However, the Utility is not precluded from recording a regulatory liability as was done in 2007.

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 2007 and 2006:

Pension Benefits

	PG&E Corporation		Utility	
	2007	2006	2007	2006
(in millions)				
Projected benefit obligation at January 1	\$ 9,064	\$ 9,249	\$ 9,023	\$ 9,211
Service cost for benefits earned ⁽¹⁾	233	236	228	233
Interest cost	544	511	541	509
Actuarial gain	(397)	(592)	(396)	(594)
Plan amendments	1	1	2	3
Benefits and expenses paid	(364)	(341)	(362)	(339)
Projected benefit obligation at December 31	<u>\$ 9,081</u>	<u>\$ 9,064</u>	<u>\$ 9,036</u>	<u>\$ 9,023</u>
Accumulated benefit obligation	<u>\$ 8,243</u>	<u>\$ 8,178</u>	<u>\$ 8,206</u>	<u>\$ 8,145</u>

⁽¹⁾ This amount includes \$2 million for the transfer of obligation from severance to the PG&E Enterprise Supplemental Executive Retirement Plan ("SERP") for PG&E Corporation.

Other Benefits

	PG&E Corporation		Utility	
	2007	2006	2007	2006
(in millions)				
Benefit obligation at January 1	\$ 1,310	\$ 1,339	\$ 1,310	\$ 1,339
Service cost for benefits earned	29	28	29	28
Interest cost	79	74	79	74
Actuarial gain	(66)	(105)	(66)	(105)
Plan amendments	17	31	17	31
Gross benefits paid	(97)	(92)	(97)	(92)
Federal subsidy on benefits paid	4	4	4	4
Participants paid benefits	35	31	35	31
Benefit obligation at December 31	<u>\$ 1,311</u>	<u>\$ 1,310</u>	<u>\$ 1,311</u>	<u>\$ 1,310</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 2007 and 2006:

Pension Benefits

	PG&E Corporation		Utility	
	2007	2006	2007	2006
(in millions)				
Fair value of plan assets at January 1	\$ 9,028	\$ 8,049	\$ 9,028	\$ 8,049
Actual return on plan assets	766	1,050	766	1,050
Company contributions	139	300	137	298
Benefits and expenses paid	(393)	(371)	(391)	(369)
Fair value of plan assets at December 31	<u>\$ 9,540</u>	<u>\$ 9,028</u>	<u>\$ 9,540</u>	<u>\$ 9,028</u>

Other Benefits

	PG&E Corporation		Utility	
	2007	2006	2007	2006
(in millions)				
Fair value of plan assets at January 1	\$ 1,256	\$ 1,146	\$ 1,256	\$ 1,146
Actual return on plan assets	107	154	107	154
Company contributions	38	25	38	25
Plan participant contribution	36	31	36	31

Benefits and expenses paid	(106)	(100)	(106)	(100)
Fair value of plan assets at December 31	<u>\$ 1,331</u>	<u>\$ 1,256</u>	<u>\$ 1,331</u>	<u>\$ 1,256</u>

Funded Status

The following schedule reconciles the plans' aggregate funded status to the prepaid or accrued benefit cost 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,	
	2007	2006	2007	2006
(in millions)				
Fair value of plan assets at December 31	\$ 9,540	\$ 9,028	\$ 9,540	\$ 9,028
Projected benefit obligation at December 31	(9,081)	(9,064)	(9,036)	(9,023)
Prepaid/(accrued) benefit cost	<u>\$ 459</u>	<u>\$ (36)</u>	<u>\$ 504</u>	<u>\$ 5</u>
Noncurrent asset	\$ 532	\$ 34	\$ 532	\$ 34
Current liability	(2)	(5)	(3)	(3)
Noncurrent liability	(71)	(65)	(25)	(26)
Prepaid/(accrued) benefit cost	<u>\$ 459</u>	<u>\$ (36)</u>	<u>\$ 504</u>	<u>\$ 5</u>

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2007	2006	2007	2006
(in millions)				
Fair value of plan assets at December 31	\$ 1,331	\$ 1,256	\$ 1,331	\$ 1,256
Benefit obligation at December 31	(1,311)	(1,310)	(1,311)	(1,310)
Prepaid/(accrued) benefit cost	<u>\$ 20</u>	<u>\$ (54)</u>	<u>\$ 20</u>	<u>\$ (54)</u>
Noncurrent asset	\$ 54	\$ -	\$ 54	\$ -
Noncurrent liability	(34)	(54)	(34)	(54)
Prepaid/(accrued) benefit cost	<u>\$ 20</u>	<u>\$ (54)</u>	<u>\$ 20</u>	<u>\$ (54)</u>

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, 2007 and 2006 were as follows:

	Pension Benefits		Other Benefits	
	2007	2006	2007	2006
(in millions)				
PG&E Corporation:				
Projected benefit obligation	\$ (73)	\$ (70)	\$ (187)	\$ (1,310)
Accumulated benefit obligation	(64)	(62)	-	-
Fair value of plan assets	-	-	153	1,256
Utility:				
Projected benefit obligation	\$ (27)	\$ (29)	\$ (187)	\$ (1,310)
Accumulated benefit obligation	(27)	(28)	-	-
Fair value of plan assets	-	-	153	1,256

Components of Net Periodic Benefit Cost

Net periodic benefit cost as reflected in PG&E Corporation's Consolidated Statements of Income for 2007, 2006, and 2005 is as follows:

Pension Benefits

(in millions)	December 31,		
	2007	2006	2005
Service cost for benefits earned ⁽¹⁾	\$ 233	\$ 236	\$ 214
Interest cost	544	511	500
Expected return on plan assets	(711)	(640)	(623)
Amortized prior service cost	49	56	56
Amortization of unrecognized loss	2	22	29
Net periodic benefit cost	\$ 117	\$ 185	\$ 176

⁽¹⁾ This amount includes \$2 million for the transfer of obligation from severance to the SERP for PG&E Corporation.

Other Benefits

(in millions)	December 31,		
	2007	2006	2005
Service cost for benefits earned	\$ 29	\$ 28	\$ 30
Interest cost	79	74	74
Expected return on plan assets	(96)	(90)	(85)
Amortized prior service cost	16	14	11
Amortization of unrecognized gain	(10)	(3)	(1)
Amortization of transition obligation	26	26	26
Net periodic benefit cost	\$ 44	\$ 49	\$ 55

There was no material difference between the Utility's and PG&E Corporation's consolidated net periodic benefit costs.

Components of Accumulated Other Comprehensive Income

On December 31, 2006, upon adoption of SFAS No. 158, PG&E Corporation and the Utility 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 will 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:

(in millions)	PG&E Corporation		Utility	
	2007	2006	2007	2006
Pension Benefits:				
Beginning unrecognized prior service cost	\$ (268)	\$ -	\$ (275)	\$ -
Adoption of SFAS No. 158	-	(268)	-	(275)
Current year unrecognized prior service cost	(3)	-	(2)	-
Amortization of unrecognized prior service cost	49	-	51	-
Unrecognized prior service cost	(222)	(268)	(226)	(275)
Beginning unrecognized net loss	(318)	-	(306)	-
Adoption of SFAS No. 158	-	(318)	-	(306)
Current year unrecognized net gain	421	-	423	-
Amortization of unrecognized net gain	2	-	-	-
Unrecognized net gain (loss)	105	(318)	117	(306)
Beginning unrecognized net transition obligation	(1)	-	(1)	-

Adoption of SFAS No. 158	-	(1)	-	(1)
Amortization of unrecognized net transition obligation	1	-	1	-
Unrecognized net transition obligation	-	(1)	-	(1)
Less: transfer to regulatory account ⁽¹⁾	109	574	109	574
Total	<u>\$ (8)</u>	<u>\$ (13)</u>	<u>\$ -</u>	<u>\$ (8)</u>

Other Benefits:

Beginning unrecognized prior service cost	\$ (114)	\$ -	\$ (114)	\$ -
Adoption of SFAS No. 158	-	(114)	-	(114)
Current year unrecognized prior service cost	(18)	-	(18)	-
Amortization of unrecognized prior service cost	16	-	16	-
Unrecognized prior service cost	<u>(116)</u>	<u>(114)</u>	<u>(116)</u>	<u>(114)</u>
Beginning unrecognized net gain	250	-	250	-
Adoption of SFAS No. 158	-	250	-	250
Current year unrecognized net gain	71	-	71	-
Amortization of unrecognized net loss	(10)	-	(10)	-
Unrecognized net gain	<u>311</u>	<u>250</u>	<u>311</u>	<u>250</u>
Beginning unrecognized net transition obligation	(154)	-	(154)	-
Adoption of SFAS No. 158	-	(154)	-	(154)
Amortization of unrecognized net transition obligation	26	-	26	-
Unrecognized net transition obligation	<u>(128)</u>	<u>(154)</u>	<u>(128)</u>	<u>(154)</u>
Less: transfer to regulatory account ⁽²⁾	(44)	-	(44)	-
Total	<u>\$ 23</u>	<u>\$ (18)</u>	<u>\$ 23</u>	<u>\$ (18)</u>

⁽¹⁾ The Utility recorded approximately \$109 million in 2007 and \$574 million in 2006 as a reduction to the existing pension regulatory liability in accordance with the provisions of SFAS No. 71.

⁽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 2008 are as follows:

	<u>PG&E Corporation</u>	<u>Utility</u>
(in millions)		
Pension benefits :		
Unrecognized prior service cost	\$ 47	\$ 48
Unrecognized net loss	1	-
Total	<u>\$ 48</u>	<u>\$ 48</u>
Other benefits:		
Unrecognized prior service cost	\$ 16	\$ 16
Unrecognized net gain	(17)	(17)
Unrecognized net transition obligation	26	26
Total	<u>\$ 25</u>	<u>\$ 25</u>

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.

	<u>Pension Benefits</u>			<u>Other Benefits</u>		
	<u>December 31,</u>			<u>December 31,</u>		
	<u>2007</u>	<u>2006</u>	<u>2005</u>	<u>2007</u>	<u>2006</u>	<u>2005</u>
Discount rate	6.31%	5.90%	5.60%	5.52-6.42%	5.50-6.00%	5.20-5.65%
Average rate of future compensation increases	5.00%	5.00%	5.00%	-	-	-

Expected return on plan assets	7.40%	8.00%	8.00%	7.00-7.50 %	7.30-8.20%	7.60-8.40%
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The assumed health care cost trend rate for 2007 is approximately 8%, decreasing gradually to an ultimate trend rate in 2011 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	\$ 72	\$ (59)
Effect on service and interest cost	8	(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 7.4% compares to a ten-year actual return of 7.9%. 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 500 Aa-grade non-callable bonds at December 31, 2007. 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 net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2007, 2006, and 2005.

Asset Allocations

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2007 and 2006, and target 2008 allocation, were as follows:

	Pension Benefits			Other Benefits		
	2008	2007	2006	2008	2007	2006
Equity securities						
U.S. equity	32%	30%	38%	37%	36%	49%
Non-U.S. equity	18%	18%	18%	18%	19%	20%
Global equity	5%	5%	5%	4%	4%	4%
Absolute return	5%	5%	0%	4%	3%	0%
Fixed income securities	40%	41%	39%	36%	37%	27%
Cash	0%	1%	0%	1%	1%	0%
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 2007, 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, 2007 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 10.5 years. The maturity of fixed income securities at December 31, 2006 ranged from zero to 60 years and the average duration of the bond portfolio was approximately 4.6 years.

PG&E Corporation's investment strategy for all plans is to maintain actual asset weightings within 0.5% to 5.5% 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 \$139 million to the pension benefits, including \$134 million to the qualified defined benefit pension plan, and approximately \$38 million to the other benefit plans in 2007. 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 in 2007. 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 2008, 2009, and 2010 to the pension plan and expect to make contributions of approximately \$58 million annually for the years 2008, 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		
2008	\$ 426	\$ 424
2009	456	453
2010	485	483
2011	514	512
2012	544	541
2013-2017	3,179	3,164
Other benefits		
2008	\$ 92	\$ 92
2009	95	95
2010	96	96
2011	98	98
2012	98	98
2013-2017	516	516

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 Internal Revenue 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/or basic contributions of up to 5% of the employee's base compensation. Matching contributions vary up to 6% 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. 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:

	PG&E Corporation	Utility
(in millions)		
Year ended December 31,		
2007	\$ 47	\$ 46
2006	45	43
2005	43	42

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 Internal Revenue 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 quarterly 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 Financial Statements. Total compensation expense recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

	PG&E Corporation	Utility
(in millions)		
2007	\$ 2	\$ 1
2006	4	2
2005	3	1

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, performance units, 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 10,847,999 shares were available for award at December 31, 2007.

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%, 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 year ended December 31, 2007:

	Year ended December 31, 2007	
	PG&E Corporation	Utility
(in millions)		
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

	Year ended December 31, 2006	
	PG&E Corporation	Utility
(in millions)		
Stock Options	\$ 12	\$ 8
Restricted Stock	20	14
Performance Shares	33	24
Total Compensation Expense (pre-tax)	\$ 65	\$ 46
Total Compensation Expense (after-tax)	\$ 39	\$ 27

Stock Options

Other than the grant of options to purchase 7,285 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 2007. 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 \$7.81, \$6.98, and \$10.08 per share in 2007, 2006, and 2005, respectively. The significant assumptions used for shares granted in 2007, 2006, and 2005 were:

	2007	2006	2005
Expected stock price volatility	16.5%	22.1%	40.6%
Expected annual dividend payment	\$ 1.44	\$ 1.32	\$ 1.20
Risk-free interest rate	4.73%	4.46%	3.74%
Expected life	5.4 years	5.6 years	5.9 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 2007, 2006, and 2005:

	PG&E Corporation	Utility
(in millions)		
2007:		
Intrinsic value of options exercised	\$ 59	\$ 34
2006:		
Intrinsic value of options exercised	\$ 97	\$ 51
2005:		
Intrinsic value of options exercised	\$ 125	\$ 57

The tax benefit from stock options exercised totaled \$20 million and \$31 million for the year ended December 31, 2007 and December 31, 2006, respectively, of which approximately \$11 million and \$44 million was recorded by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for 2007:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1	6,398,970	\$ 23.52		
Granted ⁽¹⁾	7,285	\$ 47.27		
Exercised	(2,419,272)	\$ 24.30		
Forfeited or expired	(104,311)	\$ 29.28		
Outstanding at December 31	3,882,672	\$ 24.00	4.38	\$ 74,131,879
Expected to vest at December 31	872,088	\$ 31.00	6.50	\$ 10,619,107
Exercisable at December 31	2,999,566	\$ 21.93	3.75	\$ 63,459,514

⁽¹⁾ No stock options were awarded to employees in 2007; however, certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for 2007:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1 ⁽¹⁾	4,402,506	\$ 23.66		
Granted	-	-		
Exercised	(1,414,078)	\$ 23.89		
Forfeited or expired	(77,563)	\$ 29.92		
Outstanding at December 31 ⁽¹⁾	2,910,865	\$ 23.40	4.49	\$ 57,312,688
Expected to vest at December 31	613,950	\$ 30.65	6.41	\$ 7,726,688
Exercisable at December 31	2,289,714	\$ 21.43	3.97	\$ 49,586,001

⁽¹⁾ Includes net employee transfers between PG&E Corporation and the Utility.

As of December 31, 2007, there was approximately \$2 million of total unrecognized compensation cost related to outstanding stock options, of which \$1 million was allocated to the Utility. That cost is expected to be recognized over a weighted average period of 0.5 years for PG&E Corporation and the Utility.

Restricted Stock

During 2007, PG&E Corporation awarded 607,459 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 428,960 shares were awarded to the Utility's eligible participants.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For the restricted stock awarded in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation's annual total shareholder return ("TSR") is in the top quartile of its comparator group as measured at the end of the immediately preceding year. For restricted stock awarded in 2004 and 2005, there are no performance criteria and the restrictions will lapse ratably over four years. For restricted stock awarded in 2006 and 2007, the restrictions on 60% of the shares will lapse automatically over a period of three years at the rate of 20% per year. If PG&E Corporation's annual 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 on the first business day of 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 on the first business day of the fifth year. Compensation expense related to the portion of the 2007 restricted stock award that is subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years.

The tax benefit from restricted stock which vested during 2007 and 2006 totaled \$7 million and \$4 million, respectively, of which approximately \$5 million and \$2 million was recorded by the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for 2007:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,377,538	\$ 29.27
Granted	607,459	\$ 45.82
Vested	(655,978)	\$ 23.19
Forfeited	(67,894)	\$ 39.67
Nonvested at December 31	1,261,125	\$ 39.84

The following table summarizes restricted stock activity for the Utility for 2007:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1	932,728	\$ 29.33
Granted	428,960	\$ 45.82
Vested	(446,032)	\$ 23.30
Forfeited	(60,244)	\$ 39.69
Nonvested at December 31	<u>855,412</u>	<u>\$ 39.97</u>

As of December 31, 2007, 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 1.4 years by PG&E Corporation and the Utility.

Performance Shares

During 2007, PG&E Corporation awarded 470,225 performance shares to eligible participants of PG&E Corporation and its subsidiaries, of which 320,495 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 period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive is based on the average closing price of PG&E Corporation stock for the last 30 calendar days of the year preceding the vesting date. A payout percentage is also taken into account, ranging from 0% to 200%, as measured by PG&E Corporation's TSR, relative to its comparator group, for the applicable three-year period. During 2007, PG&E Corporation paid \$18.7 million to performance share recipients, of which \$12.7 million related to Utility employees.

As of December 31, 2007, \$21 million was accrued as the performance share liability for PG&E Corporation, of which \$14.7 million related to the Utility. The number of performance shares that were outstanding at December 31, 2007 was 1,203,205, of which 853,868 was related to Utility employees. Outstanding performance shares are classified as a liability on the Consolidated Financial Statements of PG&E Corporation and the Utility because the performance shares can only be settled in cash upon satisfaction of the performance criteria. 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 performance relative to its comparator group.

NOTE 15: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

In connection with the Utility's reorganization under Chapter 11 of the U.S. Bankruptcy Code on April 12, 2004, the Utility deposited approximately \$1.7 billion into escrow for the payment of certain Disputed Claims that had been made by generators and power suppliers for transactions that occurred during the 2000-2001 California energy crisis. The Disputed Claims are being addressed in various FERC and judicial proceedings seeking refunds on behalf of California electricity purchasers (including the State of California and the Utility) from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the Power Exchange ("PX") wholesale electricity markets between May 2000 and June 2001. Many issues raised in these proceedings, including the extent of the FERC's refund authority, and the amount of potential refunds after taking into account certain costs incurred by the electricity suppliers have not been resolved. It is uncertain when these proceedings will be concluded.

The Bankruptcy Court retains jurisdiction over the Utility's escrowed funds (in addition, the Bankruptcy Court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation, or enforcement of (1) the Chapter 11 Settlement Agreement, (2) the Utility's plan of reorganization under Chapter 11, and (3) the Bankruptcy Court's order confirming the plan of reorganization).

The Utility has entered into a number of settlements with various electricity suppliers resolving some of these Disputed Claims and the Utility's refund claims against these electricity suppliers. The Bankruptcy Court has approved the release of \$0.8 billion from escrow in connection with these settlements. Through December 31, 2007, the Utility has received consideration of approximately \$1.2 billion under these settlements through cash proceeds, reductions to the Utility's PX liability, and the acquisition of Gateway. 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.

During 2007, the Utility received approximately \$79 million (including interest) in cash-equivalent reductions to the Utility's PX liability from five settlements approved by the FERC. The Utility also received two cash distributions in 2007 related to a prior settlement, totaling approximately \$34 million. These distributions will be refunded to customers through rates. On December 21, 2007, the Utility requested FERC approval of another settlement, under which, if approved, the Utility would receive \$45 million

in cash-equivalent reductions to its PX liability. 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 be credited to customers (after deductions for contingencies based on the outcome of the various refund offset and interest issues being considered by the FERC).

As of December 31, 2007, the amount of the accrual for remaining net Disputed Claims was approximately \$1.1 billion, consisting of approximately \$1.6 billion of accounts payable-Disputed Claims primarily payable to the CAISO and the PX, offset by an accounts receivable from the CAISO and the PX of approximately \$0.5 billion. The Utility held \$1.2 billion (including interest) in escrow as of December 31, 2007 for payment of the remaining net Disputed Claims. The amount held in escrow is classified as Restricted Cash in the Consolidated Balance Sheets.

As of December 31, 2007, interest on the net Disputed Claims balance, calculated at the FERC-ordered interest rate, amounts to approximately \$581 million (classified as Interest Payable in the Consolidated Balance Sheets). The rate of interest actually earned by the Utility on the escrowed amounts, however, is less than the FERC-ordered interest rate. The Utility has been collecting the difference between the earned amount and the accrued amount from customers. The amounts that have been collected from customers to address the difference between FERC-ordered and actual earned interest rates are 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 to generators, the Utility would refund to customers any excess net interest collected from customers. The ultimate amount of any interest that the Utility may be required to pay will depend on the final amount of refunds determined to be owed to the Utility.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings will ultimately 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 are priced at their fully loaded costs (i.e., direct cost of good or service plus all applicable indirect charges and overheads). 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. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

	Year Ended December 31,			Receivable (Payable) Balance Outstanding at Year Ended December 31,	
	2007	2006	2005	2007	2006
(in millions)					
Utility revenues from:					
Administrative services provided to PG&E Corporation	\$ 4	\$ 5	\$ 5	\$ 2	\$ 2
Utility employee benefit assets due from PG&E Corporation	-	-	-	27	25
Interest from PG&E Corporation on employee benefit assets	1	1	-	-	-
Utility expenses from:					
Administrative services received from PG&E Corporation	\$ 107	\$ 108	\$ 111	\$ (28)	\$ (40)
Utility employee benefit payments provided to PG&E Corporation	4	3	-	-	-

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, and legal matters.

Commitments

Utility

Third-Party Power Purchase Agreements

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 (“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, 2007, the Utility had agreements with 257 QFs for approximately 4,097 MW that are in operation. Agreements for approximately 3,754 MW expire at various dates between 2008 and 2028. QF power purchase agreements for approximately 343 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 4,097 MW consists of approximately 2,524 MW from cogeneration projects, 580 MW from wind projects and 994 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar, and hydroelectric. QF power purchase agreements accounted for approximately 20%, 20%, and 22% of the Utility’s 2007, 2006, and 2005 electricity sources, respectively. No single QF accounted for more than 5% of the Utility's 2007, 2006, or 2005 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 2008 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 3% of the Utility’s 2007 electricity sources, approximately 6% of the Utility’s 2006 electricity sources and 5% of the Utility’s 2005 electricity sources.

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, wind, solar, and geothermal energy) by at least 1% of its retail sales per year, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2010. During 2007, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. The CPUC’s decision in the Utility’s long-term procurement plan discussed below encourages the Utility to pursue the goal to meet 33% of its load with renewable resources by 2020.

Long-Term Power Purchase Agreements – In December 2007, the CPUC approved, with several modifications, the long-term electricity procurement plans (“LTPPs”) of the California investor-owned electric utilities covering the 10-year period from 2007 through 2016. Each utility is required to submit an LTPP designed to reduce greenhouse gas emissions and uses 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). The decision notes that if a previously approved contract is terminated before the generation project is built, the utilities will retain the procurement authority for the MWs subject to the terminated contract. At the end of the solicitation or request-for-offer (“RFO”) process, the utilities must justify why each bid was selected or rejected. Utilities can acquire ownership of new conventional generation resources in the utilities’ competitive RFO process only through turnkey and engineering, procurement, and construction arrangements proposed by third parties. The utilities are required to submit revised LTPPs reflecting the changes required by the CPUC within 90 days of the date the decision is mailed.

Annual Receipts and Payments – The payments made under QFs, irrigation district and water agency, renewable energy, and

other power purchase agreements during 2005 through 2007 were as follows:

(in millions)	2007	2006	2005
Qualifying facility energy payments	\$ 812	\$ 661	\$ 663
Qualifying facility capacity payments	363	366	372
Irrigation district and water agency payments	72	64	54
Renewable energy and capacity payments	604	429	405
Other power purchase agreement payments	1,166	670	774

Because the Utility acts as only an agent for the DWR, the amounts described above do not include payments related to DWR power purchases allocated to the Utility's customers.

At December 31, 2007, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	Qualifying Facility		Irrigation District & Water Agency		Renewable		Other	
	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	Energy	Capacity
2008	\$ 1,306	\$ 464	\$ 57	\$ 26	\$ 231	\$ 14	\$ 6	\$ 232
2009	1,277	423	49	26	308	11	9	210
2010	1,159	389	67	22	346	7	8	159
2011	1,141	376	35	21	488	7	8	45
2012	1,029	345	30	21	524	7	8	18
Thereafter	7,063	2,213	72	53	6,840	-	11	2
Total	\$ 12,975	\$ 4,210	\$ 310	\$ 169	\$ 8,737	\$ 46	\$ 50	\$ 666

The following table shows the future fixed capacity payments due under the QF contracts that are treated 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)	
2008	\$ 50
2009	50
2010	50
2011	50
2012	50
Thereafter	253
Total fixed capacity payments	503
Amount representing interest	131
Present value of fixed capacity payments	\$ 372

Interest and amortization expense associated with the lease obligation is included in the cost of electricity on PG&E Corporation's and the Utility's Consolidated Statements of Income. In accordance with SFAS No. 71, the timing of the Utility's capacity payments will conform to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

The Utility's Consolidated Balance Sheet has included in Current Liabilities - Other and Noncurrent Liabilities - Other approximately \$28 million and \$344 million, respectively, as of December 31, 2007, representing the present value of the fixed capacity payments due under these contracts. The corresponding assets of \$372 million, including amortization of \$36 million, are included in property, plant, and equipment on the Utility's Consolidated Balance Sheet at December 31, 2007.

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, 2007, the Utility's undiscounted obligations for natural gas purchases and gas transportation services were as follows:

(in millions)

2008	\$	1,181
2009		222
2010		22
2011		14
2012		7
Thereafter		-
Total	\$	<u>1,446</u>

Payments for natural gas purchases and gas transportation services amounted to approximately \$2.2 billion in 2007, \$2.2 billion in 2006, and \$2.5 billion in 2005.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to thirteen years and are intended to ensure long-term fuel supply. The contracts for uranium and conversion services provide for 100% coverage of reactor requirements through 2010, while contracts for enrichment services provide for 100% coverage of reactor requirements through 2009. 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, 2007, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)

2008	\$	82
2009		82
2010		113
2011		98
2012		88
Thereafter		620
Total	\$	<u>1,083</u>

Payments for nuclear fuel amounted to approximately \$102 million in 2007, \$106 million in 2006, and \$65 million in 2005.

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, 2007, the future minimum payments related to other commitments were as follows:

(in millions)

2008	\$	43
2009		16
2010		13
2011		12
2012		26
Thereafter		28
Total	\$	<u>138</u>

Payments for other commitments and operating leases amounted to approximately \$38 million in 2007, \$100 million in 2006, and \$146 million in 2005.

Underground Electric Facilities

At December 31, 2007, the Utility was committed to spending approximately \$236 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 \$50 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. At December 31, 2007, PG&E Corporation's potential exposure under this guarantee was immaterial and PG&E Corporation has not made any provision for this guarantee.

Utility

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and 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 \$38.5 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 \$10.8 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 \$10.8 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 \$100.6 million per reactor, with payments in each year limited to a maximum of \$15 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 \$201.2 million per incident, with payments in each year limited to a maximum of \$30 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 August 31, 2008.

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.

California Department of Water Resources Contracts

Electricity purchased under the DWR allocated contracts with various generators provided approximately 25% of the electricity delivered to the Utility's customers for the year ended December 31, 2007. The DWR remains legally and financially responsible for its electricity procurement 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. 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;
- 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.

On February 28, 2008, the CPUC is scheduled to vote on a proposed decision that states the CPUC would proactively investigate how the DWR can terminate its obligations under the power contracts, by assignment or otherwise, in order to hasten the reinstatement of direct access.

Severance in Connection with Efforts to Achieve Cost and Operating Efficiencies

In connection with the Utility's initiatives to streamline processes and achieve cost and operating efficiencies, the Utility is eliminating and consolidating various employee positions. As a result, the Utility has incurred severance costs and expects that it will incur additional severance costs. The amount of future severance costs will depend on many variables, including whether affected employees elect to receive severance benefits or reassignment, the number of available vacant positions for those seeking reassignment and, for those employees who elect severance benefits, their years of service and annual salaries. At December 31, 2007, the Utility estimated future severance costs will range from \$30 million to \$74 million, given the uncertainty of each of these variables. The Utility has recorded a liability of \$30 million as of December 31, 2007. The following table presents the changes in the liability from December 31, 2006:

(in millions)

Balance at December 31, 2006	\$	34
Additional severance accrued		8
Less: Payments		(12)
Balance at December 30, 2007	\$	<u>30</u>

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 reasonably likely 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 reasonably 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 \$528 million at December 31, 2007, and approximately \$511 million at December 31, 2006. The \$528 million accrued at December 31, 2007 consists of:

- Approximately \$235 million for remediation at the Hinkley and Topock natural gas compressor sites;
- Approximately \$90 million related to remediation at divested generation facilities;

- Approximately \$152 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 the fossil decommissioning sites.

Of the approximately \$528 million environmental remediation liability, approximately \$132 million has been included in prior rate setting proceedings. The Utility expects that an additional amount of approximately \$306 million will be allowable for inclusion 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.

The Utility's undiscounted future costs could increase to as much as \$834 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. The amount of approximately \$834 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.

In July 2004, the U.S. Environmental Protection Agency ("EPA") published regulations under Section 316(b) of the Clean Water Act that apply to existing electricity generation facilities that use over 50 million gallons of water per day, which typically include some form of "once-through" cooling in which water from natural bodies of water is used to cool a generating facility and the heated water is discharged back into the source. The Utility's Diablo Canyon power plant is among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The EPA regulations are intended to reduce impacts to aquatic organisms by establishing a set of performance standards for cooling water intake structures. These regulations allow site-specific compliance measures if a facility's cost of compliance is significantly greater than either the benefits to be achieved or the compliance costs considered by the EPA. The EPA regulations also allow the use of environmental mitigation or restoration to meet compliance requirements in certain cases. In response to the EPA regulations, in June 2006, the California State Water Resources Control Board ("Water Board") published a draft policy for California's implementation of Section 316(b) that proposes to eliminate the EPA's site-specific compliance options, although the draft state policy would permit environmental restoration as a compliance option for nuclear facilities if the installation of cooling towers would conflict with a nuclear safety requirement. Various parties separately challenged the EPA's regulations in court, and the cases were consolidated in the U.S. Court of Appeals for the Second Circuit ("Second Circuit"). In January 2007, the Second Circuit remanded significant provisions of the regulations to the EPA for reconsideration and held that a cost-benefit test could not be used to comply with performance standards or to obtain a variance from the standards. The Second Circuit also ruled that environmental restoration cannot be used to comply with the standard. Petitions requesting U.S. Supreme Court review of the Second Circuit decision are pending, and the EPA has suspended its regulations. It is uncertain when the EPA will issue revised regulations, whether the Supreme Court will accept review of the Second Circuit decision, how judicial developments will affect the EPA's revised regulations, how judicial developments and the EPA's revised regulations will affect the Water Board's proposed policy, and when the Water Board will issue its final policy. Depending on the nature 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.

California Labor Code Issues

Approximately 12,929 of the Utility's employees are covered by collective bargaining agreements with three labor unions: (1) the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO ("IBEW"); (2) the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, and (3) the Service Employees International Union, Local 24/7. Employees in California are entitled to an unpaid, uninterrupted 30-minute duty-free meal period for every four hours of work. California Labor Code Section 226.7 prohibits employers from requiring employees to work during any mandated meal. Employers who fail to provide the mandated meal period must provide the employee with one additional hour of pay at the employee's regular rate of compensation for each work day that the meal period is not provided. (If the employee worked during the 30-minute unpaid meal period, the employer must also pay the employee for this time.)

In April 2007, the California Supreme Court ruled that this California law requiring employers to pay an employee an additional hour of pay for each work day that a required meal is not provided is a "wage" rather than a penalty, subject to a three-year statute of limitations rather than the one-year statute of limitations for penalty payments. Prior to this decision, the Utility believed that its collective bargaining agreement with the IBEW, which did not provide certain employee groups a continuous 30-minute meal period, preempted state law.

In July 2007, the Utility established a joint committee composed of IBEW and Utility representatives to review the Utility's current collective bargaining agreements to ensure compliance with California labor law in light of the California Supreme Court's ruling. In June 2007, the Utility and the IBEW reached an agreement under which employees whose eight-hour shifts do not allow for an uninterrupted 30-minute meal break will be paid one hour of pay for each 30-minute meal period missed going back thirty-nine months. In connection with this agreement, the Utility has expensed approximately \$22 million as of December 31, 2007 for payments to approximately 2,000 employees. The Utility is continuing to investigate whether other employees may be entitled to payment for a missed or delayed meal. Until this investigation is complete, the Utility is unable to determine the amount of loss that it may incur in connection with this matter. The ultimate outcome of this matter may have a material adverse impact on PG&E Corporation's and the Utility's results of operations or financial condition.

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 provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, 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's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's Current Liabilities - Other in the Consolidated Balance Sheets, and totaled approximately \$78 million at December 31, 2007 and approximately \$74 million at December 31, 2006.

After considering the above accruals, PG&E Corporation and the Utility do not expect that losses associated with legal matters will have a material impact on their financial condition or results of operations.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter ended			
	December 31	September 30	June 30	March 31
(in millions, except per share amounts)				
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
2006				
PG&E CORPORATION				
Operating revenues	\$ 3,206	\$ 3,168	\$ 3,017	\$ 3,148
Operating income	439	735	465	469
Income from continuing operations	152	393	232	214
Net income	152	393	232	214
Earnings per common share from continuing operations, basic	0.43	1.09	0.65	0.61
Earnings per common share from continuing operations, diluted	0.43	1.09	0.65	0.60
Net income per common share, basic	0.43	1.09	0.65	0.61
Net income per common share, diluted	0.43	1.09	0.65	0.60
Common stock price per share:				
High	48.17	42.51	40.90	40.68
Low	40.72	39.06	38.30	36.25
UTILITY				
Operating revenues	\$ 3,206	\$ 3,168	\$ 3,017	\$ 3,148
Operating income	443	737	465	470
Net income	159	378	231	217
Income available for common stock	155	375	227	214

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, 2007, 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, 2007.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Financial Statements of PG&E Corporation and the Utility for the three years ended December 31, 2007, appearing in this annual report and has issued an attestation report on the effectiveness of PG&E Corporation's and the Utility's internal control over financial reporting, as stated in their report, which is included in this annual report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of PG&E Corporation and Pacific Gas and Electric Company

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, 2007 and 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the respective managements of the Company and the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2007 and 2006, and the respective results of their consolidated operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in January 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's and the Utility's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2008 expressed an unqualified opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of PG&E Corporation and Pacific Gas and Electric Company

We have audited the internal control over financial reporting of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2007, 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 maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2007 of the Company and the Utility and our report dated February 21, 2008 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph relating to accounting changes.

DELOITTE & TOUCHE LLP

San Francisco, California
February 21, 2008

Significant Subsidiaries

Parent of Significant Subsidiary	Name of Significant Subsidiary	Jurisdiction of Formation of Subsidiary	Names under which Significant Subsidiary does business
PG&E Corporation	Pacific Gas and Electric Company	CA	Pacific Gas and Electric Company PG&E
Pacific Gas and Electric Company	None		

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-121518 on Form S-3, 333-144498 on Form S-3D, and 333-16253, 333-117930, 333-46772, 333-77149, 333-73054, and 333-129422 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488 and 333-109994 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 21, 2008, 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 and incorporated by reference in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2007.

DELOITTE & TOUCHE LLP

San Francisco, California

February 21, 2008

RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION

February 20, 2008

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, 2007, 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, 2007, 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 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, 2007, 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 20, 2008; 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 20th day of February, 2008.

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 20, 2008

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, 2007, 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, 2007, 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 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 and the Vice President, Chief Financial Officer, and Controller of this company the Form 10-K Annual Report for the year ended December 31, 2007, 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 20, 2008; 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 20th day of February, 2008.

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, 2007, 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 20th day of February, 2008.

DAVID R. ANDREWS

David R. Andrews

MARYELLEN C. HERRINGER

Maryellen C. Herringer

LESLIE S. BILLER

Leslie S. Biller

RICHARD A. MESERVE

Richard A. Meserve

DAVID A. COULTER

David A. Coulter

MARY S. METZ

Mary S. Metz

C. LEE COX

C. Lee Cox

BARBARA L. RAMBO

Barbara L. Rambo

PETER A. DARBEE

Peter A. Darbee

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, 2007, 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 20th day of February, 2008.

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, 2007, 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 20th day of February, 2008.

CHRISTOPHER P. JOHNS

Christopher P. Johns

POWER OF ATTORNEY

G. ROBERT POWELL, 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, 2007, 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 20th day of February, 2008.

G. ROBERT POWELL

G. Robert Powell

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, 2007, 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 20th day of February, 2008.

DAVID R. ANDREWS

David R. Andrews

RICHARD A. MESERVE

Richard A. Meserve

LESLIE S. BILLER

Leslie S. Biller

MARY S. METZ

Mary S. Metz

DAVID A. COULTER

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WILLIAM T. MORROW

William T. Morrow

C. LEE COX

C. Lee Cox

BARBARA L. RAMBO

Barbara L. Rambo

PETER A DARBEE

Peter A. Darbee

BARRY LAWSON WILLIAMS

Barry Lawson Williams

MARYELLEN C. HERRINGER

Maryellen C. Herringer

POWER OF ATTORNEY

WILLIAM T. MORROW, 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, 2007, 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 20th day of February, 2008.

WILLIAM T. MORROW

William T. Morrow

POWER OF ATTORNEY

G. ROBERT POWELL, the undersigned, Vice President, Chief Financial Officer, 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, Chief Financial Officer, and Controller (principal financial officer and principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2007, 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 20th day of February, 2008.

G. ROBERT POWELL

G. Robert Powell

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, 2007 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 22, 2008

/s/ 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, 2007 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 22, 2008

/s/ 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, William T. Morrow, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2007 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 22, 2008

/s/ William T. Morrow

William T. Morrow
President and Chief Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, G. Robert Powell, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2007 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, 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 22, 2008

/s/ G. Robert Powell

G. Robert Powell

Vice President, Chief Financial Officer and Controller

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2007, 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) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2007, 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 such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2007, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

/s/ PETER A. DARBEE

PETER A. DARBEE

Chairman, Chief Executive Officer and President

February 22, 2008

**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, 2007, 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) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2007, 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 such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2007, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

/s/ CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer and Treasurer

February 22, 2008

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

**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 year ended December 31, 2007, I, G. Robert Powell, Vice President, Chief Financial Officer and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2007, 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 such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2007, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

/s/ G. ROBERT POWELL

G. ROBERT POWELL

Vice President, Chief Financial Officer
and Controller

February 22, 2008
