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March 9, 2001

Office of the Secretary
Federal Trade Commission
6th Street and Pennsylvania Avenue, N.W.
Room 172
Washington, D.C. 20580

FRIED FRANK HARRIS SHRIVER JACOBSON

Re: Request for Approval of Divestiture - El Paso Energy Corporation/ The Coastal Corporation - File No. 001-0086

To: Federal Trade Commission:

Pursuant to § 2.41(f) of the Federal Trade Commission's ("Commission") Rules of Practice, 16 C.F.R. § 2.41(f) (2000) and Paragraph IIIA of the Decision and Order in the above-captioned matter (the "Decision and Order"), El Paso Corporation ("El Paso"), formerly known as El Paso Energy Corporation, hereby requests approval of the sale of a .84 percent interest as a general partner in Iroquois Gas Transmission System, L.P. to Iroquois Pipeline Investment, LLC ("Iroquois Investment"), an indirect subsidiary of PG&E National Energy Group, Inc. ("PG&E NEG"), itself an indirect subsidiary of PG&E Corporation ("PG&E Corp."). Capitalized terms not herein defined shall have the same meanings set forth in the Decision and Order. As discussed with Delores Wood, I am enclosing an original and ten (10) copies of this Public version of the divestiture application and attachments.

<u>Attachments to Request for Approval of Divestiture</u>

A. The Partnership Interest Purchase and Sale Agreement (with all exhibits and schedules). This agreement is confidential and is not included in the public submission.

B. A description of the divestiture transaction.

C. A description of the purchaser.

D. A market analysis that describes how the sale of this partnership interest to Iroquois Investment will accomplish the Commission's divestiture goals as set forth in the Decision and Order.

A Partnership Including Professional Corporations

New York
Washington
Los Angeles
London
Paris

E. PG&E Corp.'s SEC and public documents, including the most recent Annual Report, 10-K, 10-Q and Proxy Statement.

If you require further information concerning Iroquois Investment's plans, please contact Peter Meier, counsel to Iroquois Investment. He can be reached at 7500 Old Georgetown Road, 13th Floor, Bethesda, Maryland, 20814, or by phone at 301-280-6817.

Pursuant to the Order, El Paso is required to complete the divestiture by April 29, 2001. Accordingly, El Paso respectfully requests that this application receive expedited treatment.

Please call me if you have any questions regarding any of the above or need any additional information or documentation.[1]

Sincerely,

Linda Blumkin
by JRD

LINDA R. BLUMKIN

cc: Jeffery Dahnke, Esq.

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1 With respect to an accounting of sales and other transactions during the previous year between El Paso and Iroquois Investment, other than ordinary course contracts entered into in 2000 between the parties, the parties are not aware of any material sales or other transactions between the parties or their affiliates in 2000.

Attachment A

Partnership Interest Purchase and Sale Agreement

The Partnership Interest Purchase and Sale Agreement is confidential and is not included in the public submission.

Attachment B

Description of the Divestiture Transaction

Transaction Overview

Iroquois Gas Transmission System, L.P. is a Delaware limited partnership (the "Partnership") of seven U.S. and Canadian energy entities, and is the owner of a 375-mile interstate natural gas pipeline extending from the U.S.-Canadian border at Waddington, N.Y. through western Connecticut to Long Island, N.Y. Its wholly-owned subsidiary, the Iroquois Pipeline Operating Company, headquartered in Shelton, Connecticut, is the agent for and operator of the pipeline.

Two of the pipeline partners, ANR Iroquois, Inc. ("ANRI") and ANR New England Pipeline Company ("ANRNE"), are subsidiaries of El Paso through ANR Pipeline Company, a Delaware corporation acquired by El Paso as a result of the Acquisition. Collectively, through ANRI and ANRNE, El Paso owns a 16 percent interest in the partnership (9.4 percent held by ANRI and 6.6 percent held by ANRNE). Pursuant to paragraph IIIA of the Decision and Order, El Paso is required to divest its interest in the Partnership not later than 90 days from the date the Commission accepted the Consent Agreement for public comment, which will expire on April 29, 2001.

ANRI and ANRNE have entered into agreements with each of the Partnership interest holders, or affiliates of existing interest holders, to which ANRI and ANRNE's interests will be divested. ANRI expects to divest its 9.4 percent interest in the Partnership in the following proportions, .84 percent to Iroquois Pipeline Investment, LLC ("Iroquois Investment"), 5.96 percent to TCPL Northeast LTD. ("TCPL"), .48 percent to NJNR Pipeline Company ("NJNR") and 2.12 percent to CNG Iroquois, Inc. ("CNG"). ANRNE expects to divest its entire 6.6 percent interest in the Partnership to CNG. By selling its 16 percent interest in the Partnership, El Paso will have divested all of its interest in the Iroquois Assets, as required by the Decision and Order. To effectuate the divestiture of its interest in the Partnership, El Paso is making separate

Requests for Approval of Divestiture for each of the four transactions that will take place.

Divestiture to Iroquois Pipeline Investment, LLC

On February 22, 2001, ANRI and Iroquois Investment, a subsidiary of PG&E NEG, executed a Partnership Interest Purchase and Sale Agreement ("Agreement") pursuant to which ANRI agreed to sell to Iroquois Investment that portion of ANRI's interest in the Partnership equal to .84 percent of the Partnership.

The Agreement contains the usual and customary conditions to closing, including approval of the Commission and applicable Attorneys General. Commission approval is also required by the Decision and Order. Other conditions include acceptance of the Decision and Order requiring the divestiture of the Iroquois Assets. The parties have requested confidential treatment with respect to the terms and conditions of the Agreement.

Attachment C

Description of the Purchaser -- Iroquois Pipeline Investment, LLC

Iroquois Investment is an indirect subsidiary of PG&E National Energy Group, Inc. ("PG&E NEG"), which itself is an indirect subsidiary of PG&E Corporation ("PG&E Corp."). PG&E Corp. is an energy based holding company with businesses which include power production, energy trading, natural gas and electric utilities and natural gas pipeline operations. PG&E Corp. had 1999 operating revenue of over $20 billion and total assets of nearly $30 billion.

PG&E NEG is one of the nation's leading competitive power producers, has natural gas facilities that connect major producing regions to some of the fastest-growing markets in North America, and operates one of the top energy trading businesses in the country. PG&E NEG currently operates 30 power plants in 10 states and has the ability to transport 2.7 billion cubic feet of natural gas on a daily basis with interconnects to 6 natural gas pipelines.

Iroquois Investment's affiliate JMC Iroquois, Inc. currently holds a 4.93 percent interest in the Partnership. Following the proposed transaction, the combined partnership interests of JMC Iroquois, Inc. and Iroquois Investment will be 5.77 percent.

Attachment D

Market Analysis

In its complaint, the Commission alleged that El Paso's acquisition of Coastal might substantially reduce competition in transportation of natural gas to the Buffalo-Niagara Falls, Rochester, Syracuse and Albany-Schenectady-Troy MSAs ("Relevant Area"). In particular, the Commission alleged that El Paso and Coastal own or control a significant share of all natural gas pipeline capacity into the Relevant Area including the Iroquois Assets. The Iroquois Assets include a 375-mile interstate natural gas pipeline extending from the U.S.-Canadian border at Waddington, N.Y. through western Connecticut to Long Island, N.Y., which is a major supplier of natural gas to the Albany-Schenectady-Troy MSA.

The major buyers of natural gas in the Relevant Area include local natural gas distribution companies, electric power generating utilities, and industrial customers. These entities buy large quantities of natural gas to resell, to use as fuel to generate electricity or for industrial processes.

Without agreeing with the Commission that El Paso's acquisition of Coastal's 16 percent interest in the Iroquois Assets would have substantially lessened competition for the transmission of natural gas to the Relevant Area, the sale of the interest to other interest holders, including Iroquois Investment, which currently holds a 4.93 percent interest in the Iroquois Assets, will eliminate any such lessening of competition. As noted above, Iroquois Investment's parent company is a large and experienced provider of retail and wholesale energy services, including gas pipeline management.

Iroquois Investment's acquisition of a .84 percent interest in the Iroquois Assets does not raise any competitive issues, as the combined interests of Iroquois Investment and its affiliate JMC Iroquois, Inc. in the Partnership, following the transaction, will amount to a minority position of only 5.77 percent, the pipeline will continue to be owned by five other entities and the pipeline will continue to be independently operated. In view of the above, the parties believe that El Paso's sale of its 16 percent interest in the Iroquois Assets to four other interest holders, including the sale of a .84 percent interest to Iroquois Investment resolves the Commission's concerns as reflected in the Complaint and complies with the Decision and Order.

Attachment E

PG&E Corp.'s SEC and Public Documents

1999 Annual Report

SEC Form 10-K for year ended December 31, 1999

SEC Form 10-Q for quarter ended September 31, 2000

Proxy Statement dated March 13, 2000

PG&E Corporation

1999 Annual Report

Corporate Overview

PG&E Corporation is a national energy-based holding company with 1999 revenues exceeding $20.8 billion and $29.7 billion in assets. It markets energy services and products throughout North America through its National Energy Group, and is the parent company of Pacific Gas and Electric Company, the Northern and Central California utility that delivers natural gas and electricity service to one in every 20 Americans.

Financial Highlights

(Unaudited, dollars in millions, except per share amounts)	1999	1998
Operating Revenues	$ 20,820	$ 19,577
Net Income (loss)		
Net income from operations	$ 826	$ 742
Items impacting comparability[1]	(899)	(23)
Reported net income (loss)	(73)	719
Earnings (loss) per Common Share, basic and diluted		
Net income from operations	$ 2.24	$ 1.94
Items impacting comparability[1]	(2.44)	(.06)
Reported net earnings (loss) per common share	$ (.20)	$ 1.88
Dividends per Common Share	$ 1.20	$ 1.20
Total Assets	$ 29,715	$ 33,234
Number of common shareholders	151,000	164,000
Number of common shares outstanding	384,406,113	382,603,564

(1) Items impacting comparability include the following in 1999: write-down of assets related to sale of Texas natural gas liquids and natural gas pipeline business of $890 million ($2.42 per share); provision for loss on sale of retail energy services unit of $58 million ($.16 per share); adjustment of litigation liability of $35 million ($.10 per share); income from change in accounting principle of $12 million ($.03 per share); and other items of $2 million ($.01 per share). Items impacting comparability in 1998 include loss on sale of Australian energy holdings of $23 million ($.06 per share).

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A Note About This Year's Report

Due to regulatory delays in our utility unit's General Rate Case, we were unable to print our traditional annual report in enough time to have it reach shareholders for the annual meeting. As a result, we are providing it to you in this form. We are preparing a summary report with more information on the Company's accomplishments and plans. If you would like a copy, please call 1.800.654.2582 or visit our website at www.pgecorp.com.

To Our Shareholders:

Your Company delivered strong operating performance in 1999.

Net income from operations grew by 11 percent. Operating revenues grew by 6 percent. And, earnings per share from operations grew by 15 percent to $2.24. These results followed strong performance in each of our businesses. Specifically, our National Energy Group grew its contribution to earnings per share by 42 percent to $0.17 per share, and Pacific Gas and Electric Company's contribution to earnings per share grew by 14 percent to $2.07.

National Energy Group

In 1999, we established the PG&E National Energy Group to integrate our national competitive business units. In 1999, this unit both grew and positioned itself for further growth.

The National Energy Group operates an electric generation portfolio of more than 7,000 megawatts. In 1999, construction continued on the Millennium Power project, a 360-megawatt natural gas-fueled plant in Charlton, Massachusetts, scheduled for operation in the fourth quarter of 2000, and we started construction of the Lake Road Generating Plant, a 792-megawatt natural gas-fueled plant in Killingly, Connecticut, scheduled for operation in 2001. Shortly after the new year, we began construction of the 1,048-megawatt natural gas-fueled La Paloma Generating Plant near Bakersfield, California. Also in 1999, we announced development of a 12-megawatt wind generating project, to be located in New York, one of the first competitive wind power generating facilities in the eastern United States. This project is scheduled to begin construction in May 2000 and to begin operation in September 2000.

Our development portfolio includes an additional 7,500 megawatts of new generating projects with planned operating dates between 2002 and 2004.

Our Northwest gas pipeline business delivered strong operational and financial performance in 1999, and we expect that to continue. It is one of the largest transporters of Canadian gas into the United States and provides about 30 percent of the natural gas supply for California, a market that continues to be among the leaders in terms of growth and demand.

In the electric part of our energy trading business, we began realizing the synergies we anticipated with our New England generating portfolio, providing the platform for our trading business to finish the year as the number one trader in the Northeast. Our energy trading operation was also instrumental in partnering with our generating business to achieve significant portfolio management successes in 1999, leveraging relationships and market expertise to restructure contracts.

We also took two actions designed to sharpen the focus of our national energy strategy and improve future earnings: we announced the sale of our Texas natural gas businesses to El Paso Energy and we took steps to sell our retail energy services business. While these actions had a one-time effect of ($2.58) per share on our 1999 reported earnings, they will result in improved earnings in 2000 and beyond.

Pacific Gas and Electric Company

Pacific Gas and Electric Company delivers energy to about one of every 20 Americans. Its Northern and Central California service territory is at the heart of one of the nation's most vibrant economies—one that saw significant gains in per capita income, falling unemployment rates, and continuing strong growth in the high-tech and services sectors last year.

This unit received base revenue increases effective in 1999 as a result of the California Public Utilities Commission's decision in its General Rate Case. This decision, along with continued cost management, provides this unit the opportunity to earn its full authorized return on equity for its distribution business.

Investments made in recent years to boost the reliability of our electric and gas distribution system are producing strong operating results. In 1999, Pacific Gas and Electric Company's customers, on average, experienced 12 percent fewer outages than in 1998. And, 91 percent of our customers who responded, when asked to rate the quality of the utility's service, rated it "good," "very good," or "excellent."

Our Diablo Canyon nuclear generating plant remains the best operating facility of its kind in the country. Last year, it received an unprecedented seventh consecutive "number one" rating from the Institute of Nuclear Power Operations, which evaluates nuclear power plants for safety and performance. The plant continues to generate significant contributions to net income.

Specific 1999 Highlights

Across the entire Company, safety performance improved in 1999. The number of lost workday incidents was down by 17 percent from 1998, and the rate of the incidents was also down. OSHA recordable incidents also declined, and are now at about half the level of five years ago.

Y2K turned out to be a non-event as we transitioned into 2000 without any significant Y2K issues, culminating several years of preparation.

We continued to build the "A" team at PG&E Corporation through learning, development, and recruiting. In 1999, this included adding two new senior executives to our management team: Thomas G. Boren as President and Chief Executive Officer of the National Energy Group, and Peter A. Darbee as Senior Vice President and Chief Financial Officer. I believe we have one of the strongest teams in the energy business, positioning us to deliver increasing value to shareholders in 2000 and beyond.

2000 and Beyond

2000 promises to be an even stronger year for your Company, and here are a few of the reasons we can see today.

Since 1997, more than 20 states have moved to open their energy markets to competition, and we see this trend of energy deregulation continuing. Our portfolio of generating plants under development is aimed at attractive markets, including those in the Northeast, Southwest, and Midwest.

Continued growth in these new generating projects and the related trading opportunities, combined with the sale of underperforming businesses, should boost the National Energy Group's performance.

And, with the decision in Pacific Gas and Electric Company's rate case having resolved the uncertainty about this unit's base revenues, it can focus more attention on continuous improvement of operations and customer service, with the goal of earning its full authorized rate of return.

Thank You

Early in 2000, our directors Richard B. Madden and Rebecca Q. Morgan retired. We thank them both for their years of service on our Boards of Directors.

Stock Price

I would have preferred to end 1999 with a higher stock price. The efforts of the PG&E Corporation team, no matter how strong and effective, do not meet the mark unless growing value is delivered to you, our shareholders. We did not do that for you in 1999. We are redoubling our efforts to provide that value to you in 2000 and beyond. The operating performance and income from operations we delivered in 1999 are the foundation for that future.

Sincerely,

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President

March 3, 2000

PG&E Corporation At A Glance

National Energy Group

	1999	1998
Operating revenues	$11.6 billion	$10.7 billion
Earnings from operations per common share	$0.17	$0.12

Products and services	Power generation Electricity and natural gas commodity supply Natural gas transportation Energy commodity trading and risk management services Electricity and natural gas for industrial, commercial, and institutional customers nationwide
Operating power plants	30, representing more than 6,500 megawatts of capacity
Power plants in development or construction	13, representing more than 10,000 megawatts
Energy trading volume in 1999:	
Gas	8.43 billion cubic feet per day
Power	224.7 million megawatt-hours
Gas pipelines	612 miles in the Pacific Northwest
Average daily natural gas throughput	2.16 billion cubic feet

Pacific Gas and Electric Company

	1999	1998
Operating revenues	$9.23 billion	$8.92 billion
Earnings from operations per common share	$2.07	$1.82

Service area	70,000 square miles in Northern and Central California, with a population of 13 million, about one in 20 Americans
Delivery systems	131,000 circuit miles of electric transmission and distribution lines, 43,000 miles of natural gas transmission and distribution pipelines
Recent investments in infrastructure	$1.2 billion in 1999, $1.4 billion in 1998
Sources of power	California Power Exchange*
Value of generating assets sold in 1999	$801 million in sales of fossil-fueled generating assets; $213 million in sales of geothermal generation facilities
A few of the customers served by Pacific Gas and Electric Company	2,592 high-tech companies, 1,123 wineries, 25 gold mines, 3,335 bakeries, 1,215 shoe stores, 1,926 video rental stores, 607 golf courses, 1,322 florists, and 1,232 car washes
Estimated energy savings through energy efficiency programs	218.2 million kilowatt-hours of electricity, or the equivalent to supply 32,200 households 4.7 million therms of natural gas, or the equivalent to supply 7,500 homes

*As a result of electric industry deregulation in California, Pacific Gas and Electric Company and other California investor-owned utilities sell all of their generated power to the California Power Exchange (PX), which also obtains power from other generating sources. The PX then distributes power to the utilities based on customer demand.

SELECTED FINANCIAL DATA

(in millions, except per share amounts)	1999	1998	1997	1996	1995
PG&E Corporation[1]					
For the Year					
Operating revenues	$20,820	$19,577	$15,255	$ 9,610	$ 9,622
Operating income	878	2,098	1,762	1,896	2,763
Income from continuing operations	13	771	745	722	1,269
Earnings per common share from continuing operations, basic and diluted	0.04	2.02	1.82	1.75	2.99
Dividends declared per common share	1.20	1.20	1.20	1.77	1.96
At Year-End					
Book value per common share	$ 19.13	$ 21.08	$ 21.30	$ 20.73	$ 20.77
Common stock price per share	20.50	31.50	30.31	21.00	28.38
Total assets	29,715	33,234	31,115	26,237	26,871
Long-term debt (excluding current portions)	6,673	7,422	7,659	7,770	8,049
Rate reduction bonds (excluding current portions)	2,031	2,321	2,611	—	—
Redeemable preferred stock and securities of subsidiaries (excluding current portions)	635	635	750	694	694
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 9,228	$ 8,924	$ 9,495	$ 9,610	$ 9,622
Operating income	1,993	1,876	1,820	1,896	2,763
Income available for common stock	763	702	735	722	1,269
At Year-End					
Total assets	$21,470	$22,950	$25,147	$26,237	$26,871
Long-term debt (excluding current portions)	4,877	5,444	6,218	7,770	8,049
Rate reduction bonds (excluding current portions)	2,031	2,321	2,611	—	—
Redeemable preferred stock and securities (excluding current portions)	586	586	694	694	694

(1) PG&E Corporation became the holding company for Pacific Gas and Electric Company on January 1, 1997. The Selected Financial Data of PG&E Corporation and Pacific Gas and Electric Company (the Utility) for the years 1995 and 1996 are identical because they reflect the accounts of the Utility as the predecessor of PG&E Corporation. Matters relating to certain data above, including discontinued operations and the cumulative effect of a change in an accounting principle are discussed in Management's Discussion and Analysis and in the Notes to Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), provides natural gas and electric service to one of every 20 Americans. PG&E Corporation's National Energy Group provides energy products and services throughout North America.

The National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC (formerly U.S. Generating Company, LLC) and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and in Texas, through various subsidiaries of PG&E Corporation (collectively, PG&E Gas Transmission or PG&E GT); purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the other National Energy Group non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading—Gas Corporation, PG&E Energy Trading—Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET); and provide competitively priced electricity, natural gas, and related services to industrial, commercial, and institutional customers through PG&E Energy Services Corporation (PG&E Energy Services or PG&E ES). In the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's Texas natural gas and natural gas liquids business. Also in the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's retail energy services.

This is a combined annual report of PG&E Corporation and Pacific Gas and Electric Company. It includes separate consolidated financial statements for each entity. The consolidated financial statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries. This Management's Discussion and Analysis (MD&A) should be read in conjunction with the consolidated financial statements included herein.

This combined annual report, including our Letter to Shareholders and this MD&A, contains forward-looking statements about the future that are necessarily subject to various risks and uncertainties. These statements are based on assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

Factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results include:

- the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States;
- operational changes related to industry restructuring, including changes in the Utility's business processes and systems;
- the method and timing of disposition and valuation of the Utility's hydroelectric generation assets;
- the timing of the completion of the Utility's transition cost recovery and the consequent end of the current electric rate freeze in California;
- any changes in the amount the Utility is allowed to collect (recover) from its customers for certain costs that prove to be uneconomic under the new competitive market (called transition costs);
- future operating performance at the Diablo Canyon Nuclear Power Plant (Diablo Canyon);
- the method adopted by the California Public Utilities Commission (CPUC) for sharing the net benefits of operating Diablo Canyon with ratepayers and the timing of the implementation of the adopted method;
- the extent of anticipated growth of transmission and distribution services in the Utility's service territory;
- future market prices for electricity;
- future fuel prices;

- the success of management's strategies to maximize shareholder value in PG&E Corporation's National Energy Group, which may include acquisitions or dispositions of assets, or internal restructuring;
- the extent to which our current or planned generation development projects are completed and the pace and cost of such completion;
- generating capacity expansion and retirements by others;
- the successful integration and performance of acquired assets;
- the outcome of the Utility's various regulatory proceedings, including the proposal to auction the Utility's hydroelectric generation assets, the electric transmission rate case applications, and post-transition period ratemaking proceedings;
- fluctuations in commodity gas, natural gas liquids, and electric prices and our ability to successfully manage such price fluctuations; and
- the pace and extent of competition in the California generation market and its impact on the Utility's costs and resulting collection of transition costs.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes we currently seek or expect. Each of these factors is discussed in greater detail in this MD&A.

In this MD&A, we first discuss our competitive and regulatory environment. We then discuss earnings and changes in our results of operations for 1999, 1998, and 1997. Finally, we discuss liquidity and financial resources, various uncertainties that could affect future earnings, and our risk management activities. Our MD&A applies to both PG&E Corporation and the Utility.

Competitive and Regulatory Environment

This section provides a discussion of the competitive environment in the evolving energy industry, the California electric industry, the California natural gas business, the National Energy Group, and regulatory matters.

The Competitive Environment in the Evolving Energy Industry

Historically, energy utilities operated as regulated monopolies within specific service territories where they were essentially the sole suppliers of natural gas and electricity services. Under this model, the energy utilities owned and operated all of the businesses necessary to procure, generate, transport, and distribute energy. These services were priced on a combined (bundled) basis, with rates charged by the energy companies designed to include all of the costs of providing these services. Now, energy utilities face intensifying pressures to "unbundle," or price separately, those activities that are no longer considered natural monopoly services. The most significant of these services are electricity generation and natural gas supply.

The driving forces behind these competitive pressures are customers who believe they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators are responding to those customers and competitors by providing for more competition in the energy industry. Regulators and legislators are requiring utilities to "unbundle" rates (separate their various energy services and the prices of those services). This allows customers to compare unit prices of the Utility and other providers when selecting their energy service provider.

In the natural gas industry, Federal Energy Regulatory Commission (FERC) Order 636 required interstate pipeline companies to divide their services into separate gas commodity sales, transportation, and storage services. Under Order 636, interstate gas pipelines must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the gas commodity from the pipeline.

In the electric industry, the Public Utilities Regulatory Policies Act of 1978 (PURPA) specifically provided that unregulated companies could become wholesale generators of electricity and that utilities were required to purchase and use power generated by these unregulated companies in meeting their customers' needs. The National Energy Policies Act of 1992 was designed and implemented through FERC Orders 888 and 889 to increase competition in the wholesale unregulated generation market by requiring access to electric utility transmission systems by all wholesale unregulated generators, sellers, and buyers of electricity. Now, an increasing number of states throughout the country either have implemented plans or are considering proposals to separate the generation from the transmission and distribution of electricity through some form of electric industry restructuring.

To date, the states, not the federal government, have taken the initiative on electric industry restructuring at the retail level. While many bills mandating restructuring of the electric industry have been introduced in Congress, none have passed. As a result, the pace, extent, and methods for restructuring the electric industry vary widely throughout the country. For instance, as of December 31, 1999, 21 states had enacted electric industry restructuring legislation, including California, Texas, Illinois, Pennsylvania, New Jersey, Massachusetts, Rhode Island, New Hampshire, and Connecticut. There also are some states that have passed legislation precluding or significantly slowing down restructuring. Differences in how individual states view electric industry restructuring often relate to the existing unit cost of energy supplies within each state. Generally, states having higher energy unit costs are moving more quickly to deregulate energy supply markets.

Implementation of our national energy strategy depends, in part, upon the opening of energy markets to provide customer choice of supplier. Undue delays by states or federal legislation to deregulate the electric generation and natural gas supply business could impact the pace of growth of our National Energy Group.

The California Electric Industry

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a competitive market framework for electric generation. Today, most Californians may continue to purchase their electricity from investor-owned utilities such as Pacific Gas and Electric Company, or they may choose to purchase electricity from alternative generation providers (such as unregulated power generators and unregulated retail electricity suppliers such as marketers, brokers, and aggregators). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as the Utility, continue to be the generation providers. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including customers who choose an alternative generation provider.

Competitive Market Framework:

To create a competitive generation market, a Power Exchange (PX) and an Independent System Operator (ISO) began operating on March 31, 1998. The PX provides a competitive auction process to establish market clearing prices for electricity in the markets operated by the PX. The ISO schedules delivery of electricity for all market participants. The Utility continues to own and maintain a portion of the transmission system, but the ISO controls the operation of the system. Unless or until the CPUC determines otherwise, the Utility is required to bid or schedule into the PX and ISO markets all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators. Also, the Utility is required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier.

In November 1999, the FERC approved the extension of the ISO's authority to establish price limitations through 2000. The ISO Board increased the applicable price limitation to $750 per megawatt-hour (MWh) on October 1, 1999, but has the option to decrease it to $500 per MWh or make other changes, in view of the FERC's decision. This limits the amount of volatility that occurs in the California electricity market. However, the ISO will review the appropriate level for any price limitations for the summer of 2000 in light of market redesign efforts now being considered, including changes to reduce uninstructed deviations from ISO dispatch orders and changes to permit loads to participate by submitting bids for price-responsive demand in energy or ancillary services markets.

The Utility is continuing its efforts to develop and implement changes to its business processes and systems, including the customer information and billing system, to accommodate electric industry restructuring. To the extent that the Utility is unable to develop and implement such changes in a successful and timely manner, there could be an adverse impact on the Utility's or PG&E Corporation's future results of operations.

Transition Period, Rate Freeze, and Rate Reduction:

California's electric industry restructuring established a transition period during which electric rates remain frozen at 1996 levels (with the exception that, on January 1, 1998, rates for small commercial and residential customers were reduced by 10 percent and remain frozen at this reduced level) and investor-owned utilities may recover their transition costs. Transition costs are generation-related costs that prove to be uneconomic under the new competitive structure. The transition period ends the earlier of December 31, 2001, or when the particular utility has recovered its eligible transition costs.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, nuclear decommissioning, and rate reduction bond debt service. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the competitive transition charge (CTC), which recovers the transition costs. These CTC revenues are being recovered from all Utility distribution customers and are subject to seasonal fluctuations in the Utility's sales volumes and certain other factors. As the CTC is collected regardless of the customer's choice of electricity supplier (i.e., the CTC is non-bypassable), the Utility believes that the availability of choice to its customers will not have a material impact on its ability to recover transition costs.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service will not increase Utility customers' electric rates. If the transition period ends before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Transition Cost Recovery:

Although most transition costs must be recovered during the transition period, certain transition costs can be recovered after the transition period. Except for certain transition costs discussed below, at the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues.

Transition costs consist of (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and that were included in customers' rates on December 20, 1995) and future sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from qualifying facilities (QF) and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods, to be included in rates in subsequent periods.)

Above-market sunk costs result when the book value of a facility exceeds its market value. Conversely, below-market sunk costs result when the market value of a facility exceeds its book value. The total amount of generation facility costs to be included as transition costs is based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. These above- and below-market sunk costs are related to generating facilities that are classified as either non-nuclear or nuclear sunk costs.

The Utility cannot determine the exact amount of above-market non-nuclear sunk costs that will be recoverable as transition costs until the valuation of the Utility's remaining non-nuclear generating assets, primarily its hydroelectric generating assets, is completed. The valuation, through appraisal, sale, or other divestiture, must be completed by December 31, 2001. The value of seven of the Utility's other non-nuclear generating facilities was determined when these facilities were sold to third parties. The portion of the sales proceeds that exceeded the book value of these facilities was used to reduce other transition costs. On September 30, 1999, the Utility filed an application with the CPUC to determine the market value of its hydroelectric generating facilities and related assets through an open, competitive auction. (See "Generation Divestiture" below.) The Utility plans to use an auction process similar to the one previously approved by the CPUC and successfully used in the sale of the Utility's fossil and geothermal plants. If the market value of the Utility's hydroelectric facilities is determined based upon any method other than a sale of the facilities to a third party, a material charge to Utility earnings could result. Any excess of market value over book value would be used to reduce other transition costs. (See "Generation Divestiture" below.)

For nuclear transition costs, revenues provided for transition cost recovery are based on the accelerated recovery of the investment in Diablo Canyon over a five-year period ending December 31, 2001. The amount of nuclear generation sunk costs was determined separately through a CPUC proceeding and was subject to a final verification audit that was completed in August 1998. The audit of the Utility's Diablo Canyon accounts at December 31, 1996, resulted in the issuance of an unqualified opinion. The audit verified that Diablo Canyon sunk costs at December 31, 1996, were $3.3 billion of the total $7.1 billion construction costs. The independent accounting firm also issued an agreed-upon special procedures report, requested by the CPUC, that questioned

$200 million of the $3.3 billion sunk costs. The CPUC will review the results of the audit and may seek to make adjustments to Diablo Canyon's sunk costs subject to transition cost recovery. At this time, the Utility cannot predict what actions, if any, the CPUC may take regarding the audit report.

Costs associated with the Utility's long-term contracts to purchase electric power are included as transition costs. Regulation required the Utility to enter into such long-term agreements with non-utility generators. Prices fixed under these contracts are now typically above prices for power in wholesale markets. (See Note 14 of Notes to Consolidated Financial Statements.) Over the remaining life of these contracts, the Utility estimates that it will purchase 299 million MWh of electric power. To the extent that the individual contract prices are above the market price, the Utility is collecting the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. The contracts expire at various dates through 2028.

The total costs under long-term contracts are based on several variables, including the capacity factors of the related generating facilities and future market prices for electricity. During 1999, the average price paid under the Utility's long-term contracts for electricity was 6.3 cents per kilowatt-hour (kWh). The average cost of electricity purchased at market rates from the PX for the year ended December 31, 1999, was 3.7 cents per kWh. The average cost of electricity purchased at market rates from the PX for the period from March 31, 1998, the PX's establishment date, to December 31, 1998, was 3.2 cents per kWh.

Generation-related regulatory assets and obligations (net generation-related regulatory assets) are included as transition costs. At December 31, 1999 and 1998, the Utility's generation-related net regulatory assets totaled $4 billion and $5.4 billion, respectively.

Certain transition costs can be recovered through a non-bypassable charge to distribution customers after the transition period. These costs include (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, (3) up to $95 million of transition costs to the extent that the recovery of such costs during the transition period was displaced by the recovery of electric industry restructuring implementation costs, and (4) transition costs financed by the rate reduction bonds. Transition costs financed by the issuance of rate reduction bonds will be recovered over the term of the bonds. In addition, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission the nuclear facility. During the rate freeze, the charge for these costs will not increase Utility customers' electric rates. Excluding these exceptions, the Utility will write off any transition costs not recovered during the transition period.

The Utility is amortizing its transition costs, including most generation-related regulatory assets, over the transition period in conjunction with the available CTC revenues. During the transition period, a reduced rate of return on common equity of 6.77 percent applies to all generation assets, including those generation assets reclassified to regulatory assets. Effective January 1, 1998, the Utility started collecting these eligible transition costs through the non-bypassable CTC and generation divestiture. For the years ended December 31, 1999 and 1998, regulatory assets related to electric industry restructuring decreased by $1,359 million and $609 million, respectively, which reflects the recovery of eligible transition costs.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition cost recovery and the amount of transition costs requested for recovery. The CPUC is currently reviewing non-nuclear transition costs amortized during 1998 and the first six months of 1999.

Generation Divestiture:

In 1998, the Utility sold three fossil-fueled generation plants for $501 million. These three fossil-fueled plants had a combined book value at the time of the sale of $346 million and had a combined capacity of 2,645 megawatts (MW).

On April 16, 1999, the Utility sold three other fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and had a combined capacity of 3,065 MW.

On May 7, 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and had a combined capacity of 1,224 MW.

The gains from the sale of the fossil-fueled generation plants were used to offset other transition costs. Likewise, the loss from the sale of the complex of geothermal generation facilities is being recovered as a transition cost.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

On September 30, 1999, the Utility filed an application with the CPUC to determine the market value of its hydroelectric generating facilities and related assets through an open, competitive auction. The Utility proposes to use an auction process similar to the one previously approved by the CPUC and successfully used in the sale of the Utility's fossil and geothermal plants. Under the process proposed in the application, another subsidiary of PG&E Corporation, PG&E Gen, would be permitted to participate in the auction on the same basis as other bidders.

The sale of the hydroelectric facilities would be subject to certain conditions, including the transfer or re-issuance of various permits and licenses by the FERC and other agencies. In addition, the FERC must approve assignment of the Utility's Reliability Must Run Contract with the ISO for any facility subject to such contract. Under the proposed purchase and sale agreement, the CPUC's approval of the proposed sale on terms acceptable to the Utility in the Utility's sole discretion is also a condition precedent to the closing of any sale.

On January 13, 2000, a scoping memo and ruling was issued that separates the proceeding into two concurrent phases: one to review the potential environmental impacts of the proposed auction under the California Environmental Quality Act and a second to determine whether the Utility's auction proposal, or some other alternative to the proposal, is in the public interest. The ruling notes that the divestiture and valuation issues can best be considered after the environmental impacts of a change in ownership have been reviewed. Potential bidders will also be able to incorporate the costs of any mitigation measures that may be required into their bids. The ruling sets a procedural schedule which calls for a final decision on the Utility's auction proposal by October 19, 2000, and a final environmental impact report published in November 2000. The ruling also anticipates that a final CPUC decision approving the sale would be issued by May 15, 2001. Finally, the ruling prohibits the Utility from withdrawing its application without express CPUC authority. It is uncertain whether the CPUC will ultimately approve the Utility's auction proposal.

At December 31, 1999, the book value of the Utility's net investment in hydroelectric generation assets was approximately $0.7 billion, excluding approximately $0.5 billion of net investment reclassified as regulatory assets. Any excess of market value over the $0.7 billion book value would be used to reduce transition costs, including the remaining $0.5 billion of regulatory assets related to the hydroelectric generation assets. If the market value of the hydroelectric generation assets is determined by any method other than a sale of the assets to a third party, or if the winning bidder for any of the auctioned assets is PG&E Gen, a material charge to Utility earnings could result. The timing and nature of any such charge is dependent upon the valuation method and procedure adopted, and the method of implementation. As discussed below, it is possible that the CPUC will require an interim valuation through an estimate of market value of the assets prior to transfer, sale, or other divestiture, which could also result in a material charge. While transfer or sale to an affiliated entity such as PG&E Gen would result in a material charge to income, neither PG&E Corporation nor the Utility believes that the sale of any generation facilities to a third party will have a material impact on its results of operations.

The Utility's ability to continue recovering its transition costs depends on several factors, including (1) the continued application of the regulatory framework established by the CPUC and state legislation, (2) the amount of transition costs ultimately approved for recovery by the CPUC, (3) the determined value of the Utility's hydroelectric generation facilities, (4) future Utility sales levels, (5) future Utility fuel and operating costs, and (6) the market price of electricity. Given the current evaluation of these factors, PG&E Corporation believes that the Utility will recover its transition costs. However, a change in one or more of these factors could affect the probability of recovery of transition costs and result in a material charge.

Post-Transition Period:

In October 1999, the CPUC issued a decision in the Utility's post-transition period ratemaking proceeding. Among other matters, the CPUC's decision addresses the mechanisms for ending the current electric rate freeze and for establishing post-transition period accounting mechanisms and rates. The decision requires Diablo Canyon generation to be priced at prevailing market rates after the transition period. This portion of the decision is further discussed below under "Regulatory Matters - Post-Transition Period Ratemaking Proceeding."

The CPUC decision requires the Utility to provide quarterly forecasts of when the Utility's rate freeze (i.e., transition period) may end based on various assumptions regarding energy prices and the book value of the Utility's remaining generation assets. The Utility is required to notify the CPUC three months before the earliest forecasted end of its rate freeze and provide draft tariff language and sample calculations of the rates that would go into effect when the rate freeze ends. After the Utility completes its transition cost recovery, it must implement its post-rate-freeze rates.

The timing of the end of the rate freeze and corresponding transition period will, in part, depend on the timing of the valuation of the Utility's hydroelectric generating assets and the ultimate determined value of such assets since any excess of market value over the assets' book value would be used to reduce transition costs. If the value of the Utility's hydroelectric generation assets is significantly higher than the related book value, the transition period and the rate freeze could end before December 31, 2001, and potentially could end during 2000. The CPUC is considering the Utility's proposal to auction its hydroelectric assets, although the CPUC could also require the Utility to implement an interim valuation of the assets. In another proceeding (the 1998 Annual Transition Cost Proceeding (ATCP)), a CPUC administrative law judge issued a proposed decision on January 7, 2000, which contained a proposed change to the rules previously in place for the amortization of transition costs. Under the final decision, issued on February 17, 2000, on a prospective basis the utilities are required to assess the estimated market value of their remaining non-nuclear generating assets, including the land associated with those assets, on an aggregate basis at a value not less than the net book value of those assets and to credit the Transition Cost Balancing Account (TCBA) with the estimated value. The decision encourages the utilities to base such estimates on realistic assessments of the market value of the assets. The final decision did not adopt the proposed decision's recommendation to establish a new regulatory asset account that would allow a true-up when the estimated market value is greater than actual market value. However, the decision states that crediting the TCBA with the aggregate net book value of the remaining non-nuclear generating assets is a conservative approach and remedies any concerns regarding the lack of a true-up. The decision provides that if the estimated market valuation is less than book value for any individual asset, accelerated amortization of the associated transition costs will continue until final market valuation of the asset occurs through sale, appraisal, or other divestiture. If the final value of the assets, determined through sale, appraisal, or other divestiture, is higher than the estimate, the excess amount would be used to pay remaining transition costs, if any. The utilities are required to file the adjusted entries to their respective TCBA based on the estimated market values with the CPUC by March 9, 2000. The filing will become effective after appropriate review by the CPUC's Energy Division and the TCBA entries are subject to review in the next ATCP. If an estimate of the market value of the non-nuclear generating assets is adopted that exceeds the aggregate net book value of those assets, a charge to earnings would result.

After the rate freeze and transition periods end, the Utility must refund to electric customers any over-collected transition costs (plus interest at the Utility's authorized rate of return) within one year after the end of the rate freeze. The Utility also will be prohibited from collecting after the rate freeze any electric costs incurred during the rate freeze but not recovered during the rate freeze, including costs that are not classified as transition costs. Through the end of its rate freeze, the Utility will continue to incur certain non-transition costs and place those costs into balancing and memorandum accounts for future recovery. There is a risk that the Utility will be unable to collect certain non-transition costs that, due to lags in the regulatory cost approval process, have not been approved for recovery nor collected when the rate freeze ends. The Utility is unable to predict the amount of such potential unrecoverable costs.

The CPUC also has established the Purchased Electric Commodity Account for the Utility to track energy costs after the rate freeze and transition period end. The CPUC intends to explore other ratemaking issues, including whether dollar-for-dollar recovery of energy costs is appropriate, in the second phase of the post-transition electric ratemaking proceeding. There are three primary options for the future regulatory framework for utility electric energy procurement cost recovery after the rate freeze: (1) a CPUC-defined procurement practice, that if followed by the Utility, would pass through costs without the need for reasonableness reviews, (2) a pass-through of costs subject to after-the-fact reasonableness reviews, or (3) a procurement incentive mechanism with rewards and penalties determined based on the Utility's energy purchasing performance compared to a benchmark. The Utility proposed adoption of either a defined procurement practice or a procurement incentive mechanism, neither of which would involve reasonableness reviews. The volatility of earnings and risk exposure of the Utility related to post-transition period purchases of electricity is dependent on which of these options, or some other approach, is adopted.

After the transition period, the Utility's future earnings from its electric distribution will be subject to volatility as a result of sales fluctuations.

Distributed Generation and Electric Distribution Competition:

In October 1999, the CPUC issued a decision outlining how the CPUC, in cooperation with other regulatory agencies and the California Legislature, plans to address the issues surrounding distributed generation, electric distribution competition, and the role of the utility distribution companies (such as Pacific Gas and Electric Company) in the competitive retail electric market. Distributed generation enables siting of electric generation technologies in close proximity to the electric demand (referred to as "load"). The CPUC decision opened a new rulemaking proceeding to examine various issues concerning distributed generation, including interconnection issues, who can own and operate distributed generation, environmental impacts, the role of utility distribution companies, and the rate design and cost allocation issues associated with the deployment of distributed generation facilities. With respect to electric distribution competition, the CPUC directed its staff to deliver a report by April 21, 2000, on the different policy options that the CPUC, in cooperation with the California Legislature, can pursue. Following the issuance of the report, the CPUC expects to open one or more new proceedings to address electric distribution competition and competition in the retail electric market.

The California Natural Gas Business

Restructuring of the natural gas industry on both the national and the state levels has given choices to California utility customers to meet their gas supply needs. The Utility offers transmission, distribution, and storage services as separate and distinct services to its industrial and larger commercial gas (noncore) customers. Customers have the opportunity to select from a menu of services offered by the Utility and they pay only for the services that they use. Access to the transmission system is possible for all gas marketers and shippers, as well as noncore end users.

The Utility's residential and smaller commercial gas (core) customers can select the commodity gas supplier of their choice. However, the Utility continues to purchase gas as a regulated supplier for those core customers who request it, serving 3.8 million core customers in its service territory.

The Utility's costs of purchasing gas for core customers through 2002 are regulated by the core procurement incentive mechanism, a form of incentive ratemaking that provides the Utility a direct financial incentive to procure gas and transportation services at the lowest reasonable costs by comparing all procurement costs to an aggregate market-based benchmark. If costs fall within a range (referred to as "tolerance band") around the benchmark, costs are considered reasonable and fully recoverable from ratepayers. If procurement costs fall outside the tolerance band, ratepayers and shareholders share savings or costs, respectively.

The Gas Accord settlement agreement, approved by the CPUC in 1997, established gas transmission rates within California for the period from March 1998 through December 2002 for the Utility's core and noncore customers and eliminated regulatory protection against variations in noncore transmission revenues. As a result, the Utility is at risk for variations between actual and forecasted transmission throughput volumes.

Rates for gas distribution services continue to be set by the CPUC and are designed to provide the Utility an opportunity to recover its costs of service and include a return on its investment. The regulatory mechanisms for setting gas distribution rates are discussed below under "Regulatory Matters."

National Energy Group

PG&E Corporation's National Energy Group has been formed to pursue opportunities created by the gradual restructuring of the energy industry across the nation. The National Energy Group integrates our national power generation, gas transmission, and energy trading and services businesses. The National Energy Group contemplates increasing PG&E Corporation's national market presence through a balanced program of acquisition and development of energy assets and businesses, while at the same time undertaking ongoing portfolio management of its assets and businesses. PG&E Corporation's ability to anticipate and capture profitable business opportunities created by restructuring will have a significant impact on PG&E Corporation's future operating results.

Certain New England states where our National Energy Group operates electric generation facilities were, like California, among the first states in the country to introduce electric industry restructuring. As a result of this restructuring and certain other regulatory initiatives, the wholesale unregulated electricity market in New England features a bid-based market and an ISO.

Independent Power Generation:

Through PG&E Gen and its affiliates, we participate in the development, construction, operation, ownership, and management of non-utility electric generating facilities that compete in the United States power generation market. In September 1998, PG&E Corporation, through its indirect subsidiary USGen New England, Inc. (USGenNE), completed the acquisition of a portfolio of electric generation assets and power supply contracts from the New England Electric System (NEES). The purchased assets include hydroelectric, coal, oil, and natural gas generation facilities with a combined generating capacity of about 4,000 MW.

Including fuel and other inventories and transaction costs, the financing requirements for this transaction were approximately $1.8 billion, funded through an aggregate of $1.3 billion of PG&E Gen and USGenNE debt and a $425 million equity contribution from PG&E Corporation. The net purchase price has been allocated as follows: (1) electric generating assets of $2.3 billion, (2) receivable for support payments of $0.8 billion, and (3) above-market contractual obligations of $1.3 billion, relating to acquired power purchase agreements, gas agreements, and standard offer agreements.

As part of the New England electric industry restructuring, the local utility companies were required to offer Standard Offer Service (SOS) to their retail customers. Retail customers may select alternative suppliers at any time. The SOS is intended to provide customers with a price benefit (the commodity electric price offered to the retail customer is expected to be less than the market price) for the first several years, followed by a price disincentive that is intended to stimulate the retail market.

Retail customers may continue to receive SOS through June 30, 2002, in New Hampshire (subject to early termination on December 31, 2000, at the discretion of the New Hampshire Public Service Commission), through December 31, 2004, in Massachusetts, and through December 31, 2009, in Rhode Island. However, if customers choose an alternate supplier, they are precluded from going back to the SOS.

In connection with the purchase of the generation assets, USGenNE entered into wholesale agreements with certain of the retail companies of NEES to supply at specified prices the electric capacity and energy requirements necessary for their retail companies to meet their SOS obligations. These companies are responsible for passing on to us the revenues generated from the SOS. USGenNE currently is indirectly serving a large portion of the SOS electric capacity and energy requirements for these companies, except in New Hampshire. For the year ended December 31, 1999, the SOS price paid to generators was $0.035 per Kwh for generation. On March 1, 1999, Constellation Power Source, Inc. (Constellation) won the New Hampshire component of the SOS through a competitive bidding solicitation. On January 7, 2000, USGenNE paid approximately $15 million to a third party for this third party's assumption of 10 percent of the Massachusetts Electric Company/Nantucket Electric Company SOS and 40 percent of the Narragansett SOS.

Like other utilities, New England utilities previously entered into agreements with unregulated companies (e.g., qualifying facilities under PURPA) to provide energy and capacity at prices that are anticipated to be in excess of market prices. We assumed NEES' contractual rights and duties under several of these power purchase agreements. At December 31, 1999, these agreements provided for an aggregate 470 MW of capacity. However, NEES will make support payments to us toward the cost of these agreements. The support payments by NEES total $0.9 billion in the aggregate (undiscounted) and are due in monthly installments from September 1998 through January 2008. In certain circumstances, with our consent, NEES may make a full or partial lump-sum accelerated payment.

Initially, approximately 90 percent of the acquired operating capacity, including capacity and energy generated by other companies and provided to us under power purchase agreements, is dedicated to servicing SOS customers. To the extent that customers eligible to receive SOS choose alternate suppliers, or as these obligations are sold to other parties, this percentage will decrease. As customers choose alternate suppliers, or the SOS obligations are sold, a greater proportion of the output of the acquired operating capacity will be subject to market prices.

Gas Transmission Operations:

PG&E Corporation participates in the "midstream" portion of the gas business through PG&E GT NW. PG&E GT NW owns and operates gas transmission pipelines and associated facilities which extend over 612 miles from the Canada-U.S. border to the Oregon-California border. PG&E GT NW provides firm and interruptible transportation services to third party shippers on an open-access basis. Its customers are principally retail gas distribution utilities, electric utilities that use natural gas to generate electricity, natural gas marketing companies, natural gas producers, and industrial consumers.

On January 27, 2000, PG&E Corporation's National Energy Group signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. (collectively, PG&E GTT). The consideration to be received by the National Energy Group includes $279 million in cash subject to a working capital adjustment, the assumption by El Paso of debt having a book value of $624 million, and other liabilities associated with PG&E GTT.

In 1999, PG&E Corporation recognized a charge against earnings of $890 million after tax, or $2.42 per share, to reflect PG&E GTT's assets at their fair market value. The composition of the pre-tax charge is as follows: (1) an $819 million write-down of net property, plant, and equipment, (2) the elimination of the unamortized portion of goodwill, in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

Proceeds from the sale will be used to retire short-term debt associated with PG&E GTT's operations and for other corporate purposes. Closing of the sale, which is expected in the first half of 2000, is subject to approval under the Hart Scott Rodino Act.

Energy Trading:

Through PG&E ET, we purchase bulk volumes of power and natural gas from PG&E Corporation affiliates and the wholesale market. We then schedule, transport, and resell these commodities, either directly to third parties or to other PG&E Corporation affiliates. PG&E ET also provides risk management services to PG&E Corporation's other businesses (except the Utility) and to wholesale customers. (See "Price Risk Management Activities" below; and Note 3 of the Notes to Consolidated Financial Statements.)

Energy Services:

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E ES, its wholly owned subsidiary, through a sale. As of December 31, 1999, the intended disposal has been accounted for as a discontinued operation. In connection with this transaction, PG&E Corporation's investment in PG&E ES was written down to its estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million. While there is no definite sales agreement, it is expected that the disposition will be completed in 2000. The amounts that PG&E Corporation will ultimately realize from this disposal could be materially different from the amounts assumed in arriving at the estimated loss on disposal of the discontinued operations. The PG&E ES business segment generated net losses of $40 million (or $0.11 per share), $52 million (or $0.14 per share), and $29 million (or $0.07 per share), for the years ended December 31, 1999, 1998, and 1997, respectively.

Regulatory Matters

A significant portion of PG&E Corporation's operations are regulated by federal and state regulatory commissions. These commissions oversee service levels and, in certain cases, PG&E Corporation's pricing for its regulated services. Following are the percentages of 1999 revenues that fell under the jurisdiction of these various regulatory agencies:

	Utility	Consolidated
Cost of service-based	96.8%	42.3%
Market	3.2%	57.7%

The Utility is the only subsidiary with significant regulatory proceedings at this time. Some of the items that affected reported 1999 results, and will affect future Utility authorized revenues, include the 1999 General Rate Case, the year 2000 cost of capital proceeding, the post-transition period ratemaking proceeding, the FERC transmission rate cases, the catastrophic event memorandum account proceeding, the CPUC's gas strategy investigation-Phase 2, and the 1997 and 1998 electric base revenue increase proceeding. These items are discussed below. Any requested change in authorized electric revenues resulting from any of the electric proceedings would not impact the Utility's customer electric rates through the transition period because these rates are frozen in accordance with the electric transition plan. However, the amount of remaining revenues providing for the recovery of transition costs would be affected. Any change in authorized gas revenues resulting from gas proceedings would increase or decrease the Utility's customer gas rates.

The 1999 General Rate Case (GRC):

In December 1997, the Utility filed its 1999 GRC application with the CPUC. During the GRC process, the CPUC examines the Utility's costs to determine the amount the Utility may charge customers for base revenues (non-fuel related costs). The Utility requested distribution revenue increases to maintain and improve natural gas and electric distribution reliability, safety, and customer service. The requested revenues, as updated, included an increase of $445 million in electric base revenues and an increase of $377 million in natural gas base revenues over the 1998 authorized revenues.

The Utility received a final decision on its 1999 GRC application on February 17, 2000. This final decision increased electric distribution revenues by $163 million and gas distribution revenues by $93 million, as compared to revenues authorized for 1998. This revenue increase is retroactive to January 1, 1999. The impact of these increases resulted in an increase in earnings of $153 million, or $0.42 per share, and was reflected in the fourth quarter of 1999.

The Utility's GRC application also contained a proposal for an Attrition Rate Adjustment (ARA) to adjust revenues in 2000 and 2001 if a performance-based ratemaking (PBR) mechanism is not adopted for 2000 or 2001. The final decision denies the Utility's request for an ARA to adjust revenues in 2000, but adopts an ARA for 2001. The final decision orders that the CPUC oversee an audit of the Utility's 1999 distribution capital spending, and that the 2001 ARA be subject to modification to take into account the results of the audit. The 2001 ARA will also be subject to modification to recognize amounts recorded in a new balancing account that the final decision requires be established for vegetation management expenses.

The Year 2000 Cost of Capital Proceeding:

In November 1999, the Utility filed its 2000 cost of capital application with the CPUC to establish its authorized rates of return on an unbundled basis for electric and natural gas distribution operations. To reflect increasing interest rates, the Utility has requested a return on equity (ROE) of 12.5 percent and an overall rate of return of 9.76 percent as compared to its 1999 authorized rates of 10.6 percent ROE and 8.75 percent overall rate of return. The Utility has not requested any change in its authorized capital structure for 2000. The Utility's current authorized capital structure is 46.2 percent long-term debt, 5.8 percent preferred stock, and 48 percent common equity.

If granted, the requested ROE would increase electric distribution revenues by approximately $127.8 million and natural gas distribution revenues by approximately $36.6 million, based on the rate base authorized in the Utility's 1999 GRC. The Utility requested that a final CPUC decision be issued in June 2000. On February 17, 2000, the CPUC issued a decision to allow the final CPUC decision, when it is adopted, to be effective retroactively to February 17, 2000.

Consistent with the rate freeze, there will be no change in electric rates in 2000. Also, the return on the Utility's electric transmission-related assets will be determined by the FERC in 2000. Finally, the return on the Utility's natural gas transmission and storage business was incorporated in rates established in the Gas Accord.

Post-Transition Period Ratemaking Proceeding:

In October 1999, the CPUC issued a decision in the Utility's post-transition period ratemaking proceeding. Among other matters, the CPUC's decision addresses the mechanisms for ending the current electric rate freeze and for establishing post-transition period accounting mechanisms and rates.

The decision prohibits the Utility from continuing to price electric generation from Diablo Canyon based on the incremental cost incentive price (ICIP) after the transition period has ended. The ICIP, which has been in place since January 1, 1997, is a performance-based mechanism that establishes a rate per kWh generated by the facility. The ICIP prices for 1999, 2000, and 2001 are 3.37 cents per kWh, 3.43 cents per kWh, and 3.49 cents per kWh, respectively. The average price for base load electric energy (the price received for a constant level of electric generation for all hours of electric demand) sold at market rates to the California PX for the 12-month period ended December 31, 1999, was 3.7 cents per kWh. The average price for base load electric energy sold at market rates to the PX from March 31, 1998, the PX's establishment date, to December 31, 1998, was 3.2 cents per kWh.

Future market prices may be higher or lower. Under the CPUC's decision, after the transition period, the Utility must price Diablo Canyon generation at the prevailing market price for power.

Further, pursuant to the 1997 CPUC decision establishing the ICIP, the Utility is required to begin sharing 50 percent of the net benefits of operating Diablo Canyon with ratepayers commencing January 1, 2002. The CPUC may interpret a more recent decision to commence the benefit-sharing at the end of the transition period. The Utility is required to file an application by July 2000 with its proposal for the methods to be used in the valuation of the benefits associated with the operation of Diablo Canyon, and the mechanism to be used to share these benefits with ratepayers. The Utility and PG&E Corporation are unable to predict what type of valuation and sharing mechanism will be adopted and what the ultimate financial impact of the sharing mechanism will have on results of operation or financial position.

The CPUC's decision also prohibits the Utility from collecting after the rate freeze any electric costs incurred but not recovered during the rate freeze, including costs that are not transition costs and are not related to generation assets such as under-collected accounting balances relating to power purchases.

See the discussion above under "Competitive and Regulatory Environment — The California Electric Industry Post-Transition Period."

In November 1999, the Utility filed an application for rehearing the CPUC's decision.

The ultimate financial impact of the provisions of the CPUC's decision described above will depend on the date the Utility's transition cost recovery is completed and the rate freeze ends, future costs including Diablo Canyon operating costs, future market prices for electricity, the amount of any electric non-transition costs that have been incurred but not recovered as of the end of the rate freeze, the timing of various regulatory proceedings in which the Utility seeks approval for rate recovery of various costs incurred during the rate freeze, and other variables that PG&E Corporation and the Utility are unable to predict.

FERC Transmission Rate Cases:

Since April 1998, all electric transmission revenues are authorized by the FERC. During 1998 and 1999, the FERC issued orders that put into effect various rates to recover electric transmission costs from the Utility's former bundled rate transmission customers. All 1998 and 1999 rates currently are subject to refund, pending final decisions in the transmission cases. In April 1999, the Utility filed a settlement with the FERC that, if approved, would allow the Utility to recover $345 million for the period of April 1998 through May 1999. In May 1999, the FERC accepted, subject to refund, the Utility's March 1999 request to begin recovering, as of May 31, 1999, $324 million annually. In October 1999, the FERC accepted, subject to refund, the Utility's request to increase revenues to $370 million annually, beginning in April 2000. The Utility does not expect a material impact on its financial position or results of operations resulting from these matters.

Catastrophic Event Memorandum Account Proceeding:

In September 1999, the Utility entered into a Settlement Agreement with the CPUC's Office of Ratepayer Advocates (ORA), and other parties, in a proceeding addressing the Catastrophic Events Memorandum Account. The settlement provides for a $59 million increase in electric distribution revenue requirement and an $11 million increase in gas distribution revenue requirement effective January 1, 2000. The increase compensates the Utility for service restoration following several events, beginning with the Oakland Hills fire of 1991 and ending with the storms of February 1998. A CPUC decision is expected in early 2000.

The CPUC's Gas Strategy Investigation, Phase 2:

In January 1998, the CPUC opened a rulemaking proceeding to explore changes in the natural gas industry in California. In July 1999, the CPUC issued a decision identifying promising options for restructuring the natural gas industry. In the decision, the CPUC reaffirmed the basic structure of the Gas Accord. The CPUC further stated that it seeks to explore a market structure that maintains the utilities' traditional role of providing fully integrated default service while removing obstacles to competitive unbundled services. The CPUC opened a new investigative proceeding to explore in more detail the anticipated costs and benefits associated with the different market structure options it has identified. On January 28, 2000, PG&E Corporation and a broad-based coalition of shippers, consumer groups, marketers, and others filed a settlement with the CPUC which would reaffirm the basic structure of the Gas Accord and continue the Gas Accord through its original term of December 31, 2002.

Electric Base Revenue Increase Proceeding:

Section 368(e) of the California Public Utilities Code was adopted as part of the California electric industry restructuring legislation. It provided for an increase in the Utility's electric base revenues for 1997 and 1998, for enhancement of transmission and distribution system safety and reliability. In accordance with Section 368(e), the CPUC authorized a 1997 base revenue increase of $164 million. For 1998, the CPUC authorized an additional base revenue increase of $77 million. Section 368(e) expenditures are subject to review by the CPUC.

In July 1999, the ORA filed reports on the Utility's Section 368(e) expenditures recommending a disallowance of $88.4 million in expenditures for 1997 and 1998. In August 1999, The Utility Reform Network (TURN) recommended an additional $14 million disallowance for a total recommended disallowance for 1997 and 1998 expenditures of $102.4 million. The Utility opposed the recommended disallowances and hearings were held in October 1999. A proposed decision is not expected until the first quarter of 2000. Any proposed decision would be subject to comment by the parties and change by the CPUC before a final decision is issued. The Utility does not expect a material impact on its financial position or results of operations resulting from these matters.

Results of Operations

In this section, we present the components of our results of operations for 1999, 1998, and 1997. The Utility received a final decision on its 1999 GRC application on February 17, 2000. As discussed further in "Regulatory Matters" above, the final decision did not increase electric revenues, although it increased the deferral of electric transition costs by $163 million over the amount that would have been deferred under the 1998 revenue requirement. This revenue increase was retroactive to January 1, 1999. The impact of the 1999 GRC resulted in an increase in earnings of $153 million, or $0.42 per share, and was reflected in the fourth quarter of 1999.

The table below shows for 1999, 1998, and 1997, certain items from our Statement of Consolidated Income detailed by Utility and National Energy Group operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for these groups.) The information for PG&E Corporation (the "Total" column) excludes transactions between its subsidiaries (such as the purchase of natural gas by the Utility from the unregulated business operations). Following this table we discuss earnings and explain why the components of our results of operations varied from the year before for 1999 and 1998.

(in millions)	Utility	National Energy Group					Total
		PG&E Gen	PG&E GT NW	PG&E GT Texas	PG&E ET	Eliminations & Other[1]	
1999							
Operating revenues	$9,228	$1,122	$224	$ 1,148	$10,521	$(1,423)	$20,820
Operating expenses	7,235	1,007	104	2,446	10,582	(1,432)	19,942
Operating income							878
Other income, net							155
Interest expense, net							(772)
Income taxes							248
Income from continuing operations							13
Net loss							$ (73)
EBITDA[2]	$3,523	$ 203	$181	$(1,178)	$ (53)	$ 19	$ 2,695
1998							
Operating revenues	$8,924	$ 649	$237	$ 1,941	$ 8,509	$ (683)	$19,577
Operating expenses	7,048	489	101	1,996	8,528	(683)	17,479
Operating income							2,098
Other income, net							65
Interest expense, net							(781)
Income taxes							611
Income from continuing operations							771
Net income							$ 719
EBITDA[2]	$3,294	$ 200	$177	$ 15	$ (15)	$ (7)	$ 3,664
1997							
Operating revenues	$9,495	$ 148	$233	$ 1,004	$ 4,808	$ (433)	$15,255
Operating expenses	7,675	176	127	1,023	4,840	(348)	13,493
Operating income							1,762
Other income, net							212
Interest expense, net							(664)
Income taxes							565
Income from continuing operations							745
Net income							$ 716
EBITDA[2]	$3,606	$ (40)	$144	$ 16	$ (29)	$ 57	$ 3,754

(1) Net income on intercompany positions recognized by segments using mark-to-market accounting is eliminated. Intercompany transactions are also eliminated.

(2) EBITDA measures earnings (after preferred dividends) before interest expense (net of interest income), income taxes, depreciation, and amortization.

Overall Results

PG&E Corporation had a net loss in 1999 of $73 million, or $0.20 per share. In 1998 PG&E Corporation had net income of $719 million, or $1.88 per share. The decrease is principally due to the write-down to fair value of our natural gas business in Texas and the accrual for the discontinuance of operations of our Energy Services segment. The PG&E GTT write-down was approximately $890 million after taxes, and the PG&E ES discontinued operations generated a charge of $58 million after tax. Partially offsetting these charges were increases in Utility income, primarily as a result of the 1999 GRC, and an adjustment of a litigation reserve associated with a court-approved settlement proposal. In addition, PG&E Gen changed its method of accounting for major maintenance and overhauls at its generating facilities. Effective January 1, 1999, PG&E Gen adopted a method that accounts for expenditures associated with major maintenance and overhauls as incurred. Previously, PG&E Gen estimated the cost of major maintenance and overhauls and accrued such costs in advance in a systematic and rational manner over the period between major maintenance and overhauls. The cumulative effect of the accounting change resulted in recognition of approximately $12 million of income, net of tax.

The Utility's net income available for common stock increased to $763 million in 1999 as compared to 1998 net income of $702 million, primarily because of the impacts of the 1999 GRC. However, the increases from the

GRC were partially offset by a reduction in the Utility's authorized cost of capital and a lower return on its assets due to the sale of a significant portion of its generating assets and recovery of transition costs (see Note 2 of the Notes to Consolidated Financial Statements).

Net income for the Utility decreased $33 million in 1998 as compared to 1997 due to the reduced rate of return on generation assets and increased interest expense associated with the rate reduction bonds.

Operating Income

Operating income for PG&E Corporation in 1999 was $878 million, which includes the charge to write down the investment in PG&E GTT to its net realizable value. Operating income for the Utility was $1,993 million in 1999 as compared to $1,876 million in 1998. This increase is primarily because of the impacts of the 1999 GRC. However, the increases from the GRC were partially offset by a reduction in the Utility's authorized cost of capital and a lower return on its assets due to the sale of a significant portion of its generating assets and recovery of transition costs (see Note 2 of the Notes to Consolidated Financial Statements).

Operating income of the National Energy Group decreased $62 million in 1999 as compared to 1998, excluding the charge to write PG&E GTT down to its net realizable value. The decline resulted from mild weather in the Northeast, lower interruptible sales in the Pacific Northwest, less portfolio management activity, and trading losses in the U.S. gas portfolio. This decline was partially offset by cost containment efforts across the organization and an increase in the differential between natural gas liquids prices and the cost of natural gas.

The operating income increase in 1998 as compared to 1997 was primarily due to the growth of the National Energy Group, which contributed $195 million of the increase. The 1998 income from continuing operations also includes a loss on the sale of our Australian energy holdings.

Operating Revenues

Utility:

Utility operating revenues increased $304 million in 1999 as compared to 1998. This increase is primarily due to: (1) a $147 million increase in gas revenues from residential and commercial gas customers due to higher usage, (2) a $93 million increase in gas revenues as a result of the GRC, (3) a $43 million increase in revenues from small and medium electric customers due to increased customers, and (4) a $16 million increase in revenues from an increase in gas transportation volumes.

Utility operating revenues decreased $571 million in 1998 as compared to 1997. This decrease is primarily due to: (1) a $410 million decrease for the 10 percent electric rate reduction provided to residential and small commercial customers, which was partially offset by $108 million of higher revenues due to increased consumption of electricity by these customers, (2) a $151 million decrease in revenues from medium and large electric customers, many of whom are now purchasing their electricity directly from unregulated power generators, (3) a $63 million decrease in sales to commercial and agricultural electric customers resulting from their lower demand for irrigation water pumping as a result of heavier rainfall in 1998, and (4) a $100 million decrease for the termination of the volumetric (ERAM) and energy cost (ECAC) revenue balancing accounts. The ERAM and ECAC accounts were replaced with the TCBA, which affects expenses, rather than revenues.

National Energy Group:

The National Energy Group's 1999 operating revenues increased $939 million as compared to 1998 operating revenues, principally due to: (1) the PG&E Gen business segment receiving a full year of revenue from the New England assets acquired in September 1998, and (2) increases in trading revenues at PG&E ET reflecting the further maturation of its business. The 1999 operating revenues also reflect revenue increases resulting from an improved differential between the natural gas liquids prices and the incoming natural gas. These revenue increases were partially offset by (1) a decline in interruptible revenues in the Northwest due to the lower natural gas prices in the Southwest as compared to Canadian prices, and (2) lower transportation revenue on the Texas transmission system. In addition, effective July 1999, certain gas trading activities conducted by PG&E GTT were transferred to PG&E ET, thus contributing to the decline in PG&E GTT revenues.

Operating revenues associated with the National Energy Group increased $4,893 million in 1998 as compared to 1997. This was primarily due to revenue increases from energy trading volumes, 12 months of revenue from the

Texas acquisitions versus seven months in 1997, portfolio management activity by PG&E Gen, and the acquisition of the New England generating assets in September 1998.

Operating Expenses

Utility:

The Utility's operating expenses increased $187 million in 1999 as compared to 1998. This increase reflects the increased cost of gas due to higher usage and the increased amortization of electric transition costs.

Utility operating expenses in 1998 decreased $627 million as compared to 1997. This decrease reflects a reduction in the amount of amortization of transition costs, primarily due to lower revenues from residential and small commercial customers discussed above in "Operating Revenues—Utility". Also contributing to the decrease in operating expenses was a reduction in gas transportation demand charges of $134 million, due to the expiration of contracted pipeline capacity.

National Energy Group:

The National Energy Group's operating expenses increased $2,276 million in 1999 as compared to 1998, due to the charge associated with the disposition of PG&E GTT, having a full year of operating expenses associated with the generation facilities in New England, and growth of PG&E ET operations.

Operating expenses for the National Energy Group increased $4,613 million in 1998 as compared to 1997. This increase reflects the increase in the volumes of energy commodities purchased, operating costs associated with the New England assets acquired in September 1998 and the gas transportation assets acquired in 1997.

Income Taxes

PG&E Corporation has recorded income tax expense of $248 million for 1999. The effective tax rate primarily results from two factors: (1) electric industry restructuring has resulted in the reversal of temporary differences whose tax benefits were originally flowed through to customers causing an increase in income tax expense independent of pre-tax income, and (2) the disposition of PG&E GTT resulted in a capital loss for tax purposes, which could not be fully recognized.

Income taxes in 1998 increased $46 million as compared to 1997. The overall effective tax rate increased 1.1 percent in 1998 largely due to accelerated book depreciation and amortization related to electric industry restructuring. These increases were partially offset by a lowered effective state tax rate resulting from our expanded business operations.

Dividends

We base our common stock dividend on a number of financial considerations, including sustainability, financial flexibility, and competitiveness with investment opportunities of similar risk. Our current quarterly common stock dividend is $.30 per common share, which corresponds to an annualized dividend of $1.20 per common share. We continually review the level of our common stock dividend, taking into consideration the impact of the changing regulatory environment throughout the nation, the resolution of asset dispositions, the operating performance of our business units, and our capital and financial resources in general.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. During 1999, the Utility has been in compliance with its CPUC-authorized capital structure. PG&E Corporation and the Utility believe that this requirement will not affect PG&E Corporation's ability to pay common stock dividends. However, depending on the timing and outcome of the valuation of the Utility's hydroelectric facilities discussed in "Generation Divestiture" above, certain valuation methods could necessitate a waiver of the CPUC's authorized capital structure in order to permit PG&E Corporation or the Utility to continue paying common stock dividends at the current level.

Liquidity and Financial Resources

Cash Flows from Operating Activities

Net cash provided by PG&E Corporation's operating activities totaled $2,287 million, $2,283 million, and $2,618 million in 1999, 1998, and 1997, respectively. Net cash provided by the Utility's operating activities totaled $2,200 million, $2,610 million, and $1,768 million in 1999, 1998, and 1997, respectively.

Cash Flows from Financing Activities

PG&E Corporation:

We fund investing activities from cash provided by operations after capital requirements and, to the extent necessary, external financing. Our policy is to finance our investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines. Based on cash provided from operations and our investing and disposition activities, we may repurchase equity and long-term debt in order to manage the overall size and balance of our capital structure.

During 1999, 1998, and 1997, we issued $54 million, $63 million, and $54 million of common stock, respectively, primarily through the Dividend Reinvestment Plan and the stock option plan component of the Long-Term Incentive Program. During 1997, we also issued $1.1 billion of common stock to acquire the natural gas assets in Texas. During 1999, 1998, and 1997, we declared dividends on our common stock of $460 million, $466 million, and $485 million, respectively.

During 1999, 1998, and 1997, we repurchased $693 million, $1,158 million, and $804 million of our common stock, respectively. The repurchases made in 1998 and through September 1999 were executed through separate, accelerated share repurchase programs. As of December 31, 1997, the Board of Directors had authorized the repurchase of up to $1.7 billion of PG&E Corporation's common stock on the open market or in negotiated transactions. As part of this authorization, in January 1998, we repurchased in a specific transaction 37 million shares of common stock. As of December 31, 1998, approximately $570 million remained available under this repurchase authorization. In February 1999, we used this remaining authorization to purchase 16.6 million shares at a cost of $502 million. In connection with this transaction, we entered into a forward contract with an investment institution. We settled the forward contract and its additional obligation of $29 million in September 1999. We used a subsidiary of PG&E Corporation to make this repurchase, along with subsequent stock repurchases. The stock held by the subsidiary is treated as treasury stock and reflected as Stock Held by Subsidiary on the Consolidated Balance Sheet of PG&E Corporation.

In October 1999, the Board of Directors of PG&E Corporation authorized an additional $500 million for the purpose of repurchasing shares of the Corporation's common stock on the open market. This authorization supplements the approximately $40 million remaining from the amount previously authorized by the Board of Directors on December 17, 1997. The authorization for share repurchase extends through September 30, 2001. As of December 31, 1999, through our wholly owned subsidiary, we repurchased 7.2 million shares, at a cost of $159 million under this authorization. Any open market purchases will be made by the wholly owned subsidiary of PG&E Corporation.

During 1999, our National Energy Group retired $128 million of long-term debt. This amount includes PG&E GTT's June 1999 redemption of the outstanding balance of $69 million of its senior notes, which resulted in a gain on redemption of approximately $1.7 million. In 1998, our National Energy Group retired $75 million of long-term debt and retired the notes used in the acquisition of our Australian energy holdings. In 1997, our National Energy Group issued $30 million and retired $109 million of long-term debt. Also in 1997, we assumed $780 million of long-term debt in connection with the acquisition of our natural gas assets in Texas.

We maintain a number of credit facilities to support commercial paper programs, letters of credit, and other short-term liquidity requirements. PG&E Corporation maintains two $500 million revolving credit facilities, one of which expires in November 2000 and the other in 2002. These credit facilities are used to support the commercial paper program and other liquidity needs. The facility expiring in 2000 may be extended annually for additional one-year periods upon agreement with the lending institutions. There was $450 million of commercial paper outstanding at December 31, 1999. PG&E Corporation introduced a $200 million Extendible Commercial Note (ECN) program during the third quarter of 1999. The ECN program supplements our short-term borrowing capability. There was $76 million of extendible commercial notes outstanding at December 31, 1999, which are not supported by the credit facilities.

PG&E Gen maintains two $550 million revolving credit facilities. One facility expires in August 2000 and the other expires in 2003. The total amount outstanding at December 31, 1999, backed by the facilities, was $898 million in commercial paper. Of these loans, $550 million is classified as noncurrent in the Consolidated Balance Sheet of PG&E Corporation.

In 1998, USGenNE, a subsidiary of PG&E Gen, established a $100 million revolving credit facility that expires in 2003. As of December 31, 1999, there is no outstanding balance on this facility.

PG&E GT NW maintains a $100 million revolving credit facility that expires in 2002, but has an annual renewal option allowing the facility to maintain a three-year duration. PG&E GT NW also maintains a $50 million 364-day credit facility that expires in 2000, but can be extended for successive 364-day periods. At December 31, 1999, PG&E GT NW had an outstanding commercial paper balance of $99 million, which is classified as noncurrent in the Consolidated Balance Sheet of PG&E Corporation.

PG&E GTT maintains four separate credit facilities that total $250 million and are guaranteed by PG&E Corporation. At December 31, 1999, PG&E GTT had $176 million of outstanding short-term bank borrowings related to these credit facilities. These lines may be cancelled upon demand and bear interest at each respective bank's quoted money market rate. The borrowings are unsecured and unrestricted as to use.

Utility:

In December 1999, 7.6 million shares of the Utility's common stock, with an aggregate purchase price of $200 million, was purchased by a subsidiary of the Utility. This purchase is reflected as stock held by subsidiary in the Consolidated Balance Sheet of Pacific Gas and Electric Company. Earlier in 1999, the Utility repurchased and cancelled 20 million shares of its common stock from PG&E Corporation for an aggregate purchase price of $726 million to maintain its authorized capital structure. In 1999, 1998, and 1997, the Utility declared dividends on its common stock of $415 million, $300 million, and $699 million, respectively.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 1999 totaled $654 million. Of this amount, (1) $290 million related to the Utility's rate reduction bonds maturing, (2) $135 million related to the Utility's repurchase of mortgage and various other bonds, (3) $147 million related to maturity of various utility mortgage bonds, and (4) $82 million related to the maturities and redemption of various of the Utility's medium-term notes and other debt.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during 1998 totaled $1.4 billion. Of this amount, (1) $249 million related to the Utility's redemption of its 8% mortgage bonds due October 1, 2025, (2) $252 million related to the Utility's repurchase of various other mortgage bonds, (3) $397 million related to the maturity of the Utility's 5⅜% mortgage bonds, (4) $204 million related to the other scheduled maturities of long-term debt, and (5) $290 million related to rate reduction bonds maturing.

In 1997, the Utility redeemed or repurchased $225 million of long-term debt to manage the overall balance of its capital structure. Also in 1997, the Utility replaced $360 million of fixed interest rate pollution control bonds with the same amount of variable interest rate pollution control bonds.

During 1999 and 1997, the Utility did not redeem or repurchase any of its preferred stock. In 1998, the Utility redeemed its Series 7.44% preferred stock with a face value of $65 million and its Series 6⅞% preferred stock with a face value of $43 million.

In December 1997, a subsidiary of the Utility issued $2.9 billion of rate reduction bonds through a special-purpose entity established by the California Infrastructure and Economic Development Bank. The proceeds were used by the Utility to retire debt and reduce equity. (See Note 9 of Notes to Consolidated Financial Statements.)

The Utility maintains a $1 billion revolving credit facility, which expires in 2002. The Utility may extend the facility annually for additional one-year periods upon agreement with the banks. This facility is used to support the Utility's commercial paper program and other liquidity requirements. The total amount outstanding at December 31, 1999, backed by this facility, was $449 million in commercial paper. There were no bank notes outstanding at December 31, 1999.

Cash Flows from Investing Activities

Utility:

The primary uses of cash for investing activities are additions to property, plant, and equipment, unregulated investments in partnerships, and acquisitions.

The Utility's estimated capital spending for 2000 is approximately $1.3 billion, excluding capital expenditures for divested fossil and geothermal power plants. The Utility's capital expenditures were $1,181 million, $1,382 million, and $1,522 million for the years ended December 31, 1999, 1998, and 1997, respectively.

During 1999, the Utility sold three fossil-fueled generation facilities and its geothermal generation facilities. These sales closed in April and May 1999, respectively, and generated proceeds of $1,014 million. In 1998, the Utility had proceeds of $501 million from the sale of three fossil-fueled generation plants.

National Energy Group:

PG&E Gen is associated with the construction of two natural gas-fueled combined-cycle power plants, and plans to begin construction on a third plant in early 2000. These power plants, referred to as "merchant power plants," will sell power as a commodity in the competitive marketplace. The electricity generated by these plants will be sold on a wholesale basis to local utilities and power marketers, including PG&E ET, which, in turn, will sell it to industrial, commercial, and other electricity customers.

Millennium Power, a 360-MW power plant located in Massachusetts, is scheduled to begin commercial service in the fourth quarter of 2000. Lake Road Generating Plant (Lake Road), an approximately 790-MW power plant located in Connecticut, is scheduled to begin commercial service in 2001. Lake Road is being financed through a synthetic lease with a third party owner. PG&E Gen will operate the plant under an operating lease (See Note 14 of Notes to Consolidated Financial Statements). La Paloma Generating Plant, an approximately 1,050-MW power plant, is located in California, and is scheduled to begin commercial service in 2002. The estimated cost to construct these plants is approximately $1.4 billion.

In 1998, PG&E Corporation sold its Australian energy holdings for proceeds of approximately $126 million. In 1997, PG&E Corporation sold its interest in International Generating Company, Ltd., resulting in an after-tax gain of approximately $120 million.

Debt Obligations and Rate Reduction Bonds

The table below provides information about our debt obligations and rate reduction bonds at December 31, 1999:

Expected maturity date	**2000**	**2001**	**2002**	**2003**	**2004**	**There-after**	**Total**	**Fair Value at Dec. 31, 1999**
(dollars in millions)								
Utility:								
Long-term debt								
Variable rate obligations	$200	$100	$738	$310	$ —	$ —	$1,348	$1,348
Fixed rate obligations	$265	$274	$379	$354	$392	$2,330	$3,994	$3,869
Average interest rate	6.6%	8.0%	7.8%	6.3%	6.4%	7.1%	7.1%	
Rate reduction bonds	$290	$290	$290	$290	$290	$ 871	$2,321	$2,265
Average interest rate	6.2%	6.2%	6.3%	6.4%	6.4%	6.5%	6.3%	
National Energy Group:								
Long-term debt								
Variable rate obligations	$ 44	$ 11	$109	$560	$ 9	$ 87	$ 820	$ 820
Fixed rate obligations	$ 83	$ 95	$137	$ 47	$ 69	$ 672	$1,103	$1,058
Average interest rate	8.5%	9.1%	8.6%	9.8%	9.8%	8.2%	8.5%	

Environmental Matters

We are subject to laws and regulations established to both maintain and improve the quality of the environment. Where our properties contain hazardous substances, these laws and regulations require us to remove those substances or remedy effects on the environment.

At December 31, 1999, the Utility has accrued $271 million ($300 million on an undiscounted basis) for clean-up costs at identified sites. If other responsible parties fail to pay or expected outcomes change, then these costs may be as much as $486 million. Of the $271 million, the Utility has recovered $148 million through rates, including $34 million through depreciation and expects to recover another $95 million in future rates. Additionally, the Utility mitigates its cost by seeking recovery from insurance carriers and other third parties. (See Note 15 of Notes to Consolidated Financial Statements.)

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate 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 estimates the upper limit of the range using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or expected outcomes change.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Regional Water Quality Control Board (Central Coast Board). The purchaser notified the Central Coast Board of its findings and the Central Coast Board requested additional information from the purchaser. The Utility has initiated an investigation of these activities during the time it owned the plant. The Central Coast Board has been notified of the investigation and the results will be presented to the Central Coast Board when the investigation is complete. If the identified procedure was performed during the Utility's ownership and was beyond the scope of the relevant NPDES permits, the Central Coast Board may choose to initiate an enforcement action. If so, the Utility could be subject to significant penalties. Until the investigation is complete and the results discussed with the Central Coast Board, it is not possible to determine whether the Utility will suffer a loss in connection with this matter or to provide a more detailed estimate of such liability.

Year 2000 (Y2K)

PG&E Corporation successfully transitioned into the Year 2000 without any Y2K-related service disruptions. There is, however, a risk that some computer-related problems might not manifest themselves for a period of time and that supplier or business partner Y2K problems may materialize and have an adverse impact on our operations.

As of December 31, 1999, expenditures to address potential Y2K problems totaled $185 million, of which $93 million is attributed to the Utility. Included are systems replaced or enhanced for general business purposes and for which implementation schedules were critical to our Y2K readiness.

Inflation

Financial statements, which are prepared in accordance with generally accepted accounting principles, report operating results in terms of historical costs and do not evaluate the impact of inflation. Inflation affects our construction costs, operating expenses, and interest charges. In addition, the Utility's electric revenues will not reflect the impact of inflation due to the current electric rate freeze. However, inflation at current levels is not expected to have a material adverse impact on the Utility's or our financial position or results of operations.

Price Risk Management Activities

We have established a risk management policy that allows derivatives to be used for both hedging and non-hedging purposes (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset). We use derivatives for hedging purposes primarily to offset underlying commodity price risks. We also participate in markets using derivatives to gather market intelligence, create liquidity, and maintain a market presence. Such derivatives include forward contracts, futures, swaps, and options. Net open positions often exist or are established due to PG&E Corporation's assessment of its response to changing market conditions. To the extent that PG&E Corporation has an open position, it is exposed to the risk that fluctuating market prices may adversely impact its financial results. Our risk management policy and the trading and risk management policies of our subsidiaries prohibit the use of derivatives whose payment formula includes a multiple of some underlying asset.

We prepare a daily assessment of our portfolio market risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the size and probability of future potential losses. The quantification of market risk using value-at-risk provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period.

We utilize historical data for calculating the price volatility of our positions and how likely the prices of those positions will move together. The model includes all derivative and commodity investments in our non-hedging portfolio and only derivative commodity investments for our hedging portfolio (but not the related underlying hedged position). We express value-at-risk as a dollar amount of the potential loss in the fair value of our portfolio based on a 95 percent confidence level using a one-day liquidation period. Therefore, there is a 5 percent probability that our portfolio will incur a loss in one day greater than our value-at-risk. The value-at-risk is aggregated for PG&E Corporation as a whole by correlating the daily returns of the portfolios for natural gas, natural gas liquids, and power for the previous 22 trading days. Our daily value-at-risk for commodity price-sensitive derivative instruments as of December 31, 1999 and 1998, for non-hedging activities was $4.4 million and $6.2 million, respectively. Our daily value-at-risk for commodity price-sensitive derivative instruments as of December 31, 1999 and 1998, for hedging activities was $30,000 and $210,000, respectively. For the year ended December 31, 1999, the average, high, and low value-at-risk amounts for non-hedging activities were $4.3 million, $6.2 million, and $1.3 million, respectively. The average, high, and low value-at-risk amounts over the same reporting period for hedging activities were $0.6 million, $1.7 million, and $0.0 million, respectively. The average, high and low amounts for the reporting period were computed using the value-at-risk amounts at the beginning of the reporting period and the four quarter-end amounts.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities.

In June 1999, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 137, "Accounting for Derivative Instruments and Hedging Activities-Deferral of the Effective Date of FASB Statement No. 133," which delayed the implementation of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," by one year to require adoption in years beginning after June 15, 2000. The Statement permits early adoption as of the beginning of any fiscal quarter.

PG&E Corporation expects to adopt SFAS No. 133 no later than January 1, 2001. The Statement will require us to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. We currently are evaluating what the effect of SFAS No. 133 will be on the earnings and financial position of PG&E Corporation. However, we already use the mark-to-market method of accounting for our commodity non-hedging and price risk management activities.

Legal Matters

In the normal course of business, both the Utility and PG&E Corporation are named as parties in a number of claims and lawsuits. (See Note 15 of Notes to Consolidated Financial Statements for further discussion of significant pending legal matters.)

PG&E Corporation

Statement of Consolidated Income
(in millions, except per share amounts)

	Year ended December 31, 1999	1998	1997
Operating Revenues			
Utility	$ 9,228	$ 8,924	$ 9,495
Energy commodities and services	11,592	10,653	5,760
Total operating revenues	20,820	19,577	15,255
Operating Expenses			
Cost of energy for utility	3,149	2,942	3,208
Cost of energy commodities and services	10,587	9,852	5,368
Operating and maintenance, net	3,151	3,083	3,066
Depreciation, amortization, and decommissioning	1,780	1,602	1,851
Loss on assets held for sale	1,275	—	—
Total operating expenses	19,942	17,479	13,493
Operating Income	878	2,098	1,762
Interest expense, net	(772)	(781)	(664)
Other income, net	155	65	212
Income Before Income Taxes	261	1,382	1,310
Income taxes	248	611	565
Income from continuing operations	13	771	745
Discontinued operations (Note 5)			
Loss from operations of PG&E Energy Services (net of applicable income taxes of $35 million, $41 million, and $17 million, respectively)	(40)	(52)	(29)
Loss on disposal of PG&E Energy Services (net of applicable income taxes of $36 million)	(58)	—	—
Net income (loss) before cumulative effect of a change in accounting principle (Note 1)	(85)	719	716
Cumulative effect of a change in an accounting principle (net of applicable income taxes of $8 million)	12	—	—
Net Income (loss)	$ (73)	$ 719	$ 716
Weighted Average Common Shares Outstanding	368	382	410
Earnings (Loss) Per Common Share, Basic and Diluted			
Income from continuing operations	$ 0.04	$ 2.02	$ 1.82
Discontinued operations	(0.27)	(0.14)	(0.07)
Cumulative effect of a change in an accounting principle	0.03	—	—
Net income (loss)	$ (0.20)	$ 1.88	$ 1.75
Dividends Declared Per Common Share	$ 1.20	$ 1.20	$ 1.20

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

Consolidated Balance Sheet
(in millions, except share amounts)

	Balance at December 31, 1999	1998
Assets		
Current Assets		
Cash and cash equivalents	$ 281	$ 286
Short-term investments	187	55
Accounts receivable		
Customers, net	1,486	1,856
Energy marketing	532	507
Price risk management	607	1,416
Inventories and prepayments	598	671
Deferred income taxes	133	—
Total current assets	3,824	4,791
Property, Plant, and Equipment		
Utility	23,001	24,160
Non-utility		
Electric generation	1,905	1,967
Gas transmission	2,541	3,347
Construction work in progress	436	407
Other	184	127
Total property, plant, and equipment (at original cost)	28,067	30,008
Accumulated depreciation and decommissioning	(11,291)	(12,026)
Net property, plant, and equipment	16,776	17,982
Other Noncurrent Assets		
Regulatory assets	4,957	6,347
Nuclear decommissioning funds	1,264	1,172
Other	2,894	2,942
Total noncurrent assets	9,115	10,461
Total Assets	$ 29,715	$ 33,234

PG&E Corporation

Consolidated Balance Sheet (Continued)
(in millions, except share amounts)

	Balance at December 31, 1999	1998
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 1,499	$ 1,644
Current portion of long-term debt	592	338
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	708	1,001
Other	559	443
Regulatory balancing accounts	384	79
Energy marketing	480	381
Accrued taxes	211	103
Price risk management	575	1,412
Other	1,033	1,064
Total current liabilities	6,331	6,755
Noncurrent Liabilities		
Long-term debt	6,673	7,422
Rate reduction bonds	2,031	2,321
Deferred income taxes	3,147	3,861
Deferred tax credits	231	283
Other	3,636	3,746
Total noncurrent liabilities	15,718	17,633
Preferred Stock of Subsidiaries	480	480
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	300	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued, 384,406,113 and 382,603,564 shares, respectively	5,906	5,862
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	—
Reinvested earnings	1,670	2,204
Total common stockholders' equity	6,886	8,066
Commitments and Contingencies (Notes 1, 2, 3, 4, 5, 14, and 15)	—	—
Total Liabilities and Stockholders' Equity	$29,715	$33,234

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

PG&E Corporation

Statement of Consolidated Cash Flows
(in millions)

	For the year ended December 31,		
	1999	**1998**	**1997**
Cash flows from Operating Activities			
Net (loss) income	$ (73)	$ 719	$ 716
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,780	1,602	1,851
Deferred income taxes and tax credits—net	(754)	(107)	(160)
Other deferred charges and noncurrent liabilties	102	18	121
Loss (gain) on sale of assets	—	23	(120)
Loss on assets held for sale	1,275	—	—
Loss from discontinued operations	98	52	29
Cumulative effect of change in accounting principle	(12)	—	—
Net effect of changes in operating assets and liabilities:			
Accounts receivable—trade	370	(342)	(242)
Inventories and prepayments	73	(179)	(4)
Price risk management assets and liabilities, net	(28)	(16)	12
Accounts payable—trade	(293)	247	210
Regulatory balancing accounts payable	305	537	126
Accrued taxes	108	(123)	(54)
Other working capital	159	199	(85)
Other—net	(824)	(347)	218
Cash provided in discontinued operations	1	—	—
Net cash provided by operating activities	2,287	2,283	2,618
Cash Flows From Investing Activities			
Capital expenditures	(1,584)	(1,619)	(1,822)
Acquisitions and investments in unregulated projects	—	(1,779)	(116)
Proceeds from sale of assets	1,014	1,106	146
Other—net	453	66	21
Net cash used by investing activities	(117)	(2,226)	(1,771)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	(145)	2,115	(587)
Long-term debt issued	—	—	386
Long-term debt matured, redeemed, or repurchased	(798)	(1,552)	(961)
Proceeds from issuance of rate reduction bonds	—	—	2,881
Preferred stock redeemed or repurchased	—	(108)	—
Common stock issued	54	63	54
Common stock repurchased	(693)	(1,158)	(804)
Dividends paid	(465)	(470)	(524)
Other—net	4	(3)	(39)
Net cash provided (used) by financing activities	(2,043)	(1,113)	406
Net Change in Cash and Cash Equivalents	127	(1,056)	1,253
Cash and Cash Equivalents at January 1	341	1,397	144
Cash and Cash Equivalents at December 31	$ 468	$ 341	$ 1,397
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 727	$ 774	$ 624
Income taxes (net of refunds)	723	770	801

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statment.

PG&E Corporation

Statement of Consolidated Common Stock Equity
(in millions, except share amounts)

	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Total Common Stock Equity
Balance December 31, 1996	$2,018	$ 3,710	$ —	$2,636	$ 8,364
Net income				716	716
Holding company formation	3,710	(3,710)			—
Common stock issued (2,302,544 shares)	54				54
Acquisitions (45,683,005 shares)	1,069				1,069
Common stock repurchased (33,823,950 shares)	(496)			(308)	(804)
Cash dividends declared on common stock				(485)	(485)
Other	11			(28)	(17)
Balance December 31, 1997	6,366	—	—	2,531	8,897
Net income				719	719
Common stock issued (2,028,303 shares)	63				63
Common stock repurchased (37,090,630 shares)	(565)			(593)	(1,158)
Cash dividends declared on common stock				(466)	(466)
Other	(2)			13	11
Balance December 31, 1998	5,862	—	—	2,204	8,066
Net loss				(73)	(73)
Common stock issued (1,879,474 shares)	54				54
Common stock repurchased (23,892,425 shares)	(2)		(690)	(1)	(693)
Cash dividends declared on common stock				(460)	(460)
Other	(8)				(8)
Balance December 31, 1999	$5,906	$ —	$(690)	$1,670	$ 6,886

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

Statement of Consolidated Income
(in millions)

	Year ended December 31, 1999	1998	1997
Operating Revenues			
Electric	$7,232	$7,191	$7,691
Gas	1,996	1,733	1,804
Total operating revenues	9,228	8,924	9,495
Operating Expenses			
Cost of electric energy	2,411	2,321	2,501
Cost of gas	738	621	707
Operating and maintenance, net	2,522	2,668	2,719
Depreciation, amortization, and decommissioning	1,564	1,438	1,748
Total operating expenses	7,235	7,048	7,675
Operating Income	1,993	1,876	1,820
Interest expense, net	(593)	(621)	(570)
Other income, net	36	103	127
Income Before Income Taxes	1,436	1,358	1,377
Income taxes	648	629	609
Net Income	788	729	768
Preferred dividend requirement	25	27	33
Income Available for Common Stock	$ 763	$ 702	$ 735

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

Consolidated Balance Sheet
(in millions, except share amounts)

	Balance at December 31, 1999	Balance at December 31, 1998
Assets		
Current Assets		
Cash and cash equivalents	$ 80	$ 73
Short-term investments	21	17
Accounts receivable		
Customers, net	1,201	1,383
Related parties	9	14
Inventories		
Fuel oil	2	23
Gas stored underground	137	130
Materials and supplies	155	159
Prepayments	34	50
Deferred income taxes	119	—
Total current assets	1,758	1,849
Property, Plant, and Equipment		
Electric	15,762	17,088
Gas	7,239	7,072
Construction work in progress	214	273
Total property, plant, and equipment (at original cost)	23,215	24,433
Accumulated depreciation and decommissioning	(10,497)	(11,397)
Net property, plant, and equipment	12,718	13,036
Other Noncurrent Assets		
Regulatory assets	4,895	6,288
Nuclear decommissioning funds	1,264	1,172
Other	835	605
Total noncurrent assets	6,994	8,065
Total Assets	$ 21,470	$ 22,950

Pacific Gas and Electric Company

Consolidated Balance Sheet (Continued)
(in millions, except share amounts)

	Balance at December 31, 1999	1998
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 449	$ 668
Current portion of long-term debt	465	260
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	577	718
Related parties	216	60
Regulatory balancing accounts	384	79
Other	333	374
Accrued taxes	118	2
Other	529	561
Total current liabilities	3,361	3,012
Noncurrent Liabilities		
Long-term debt	4,877	5,444
Rate reduction bonds	2,031	2,321
Deferred income taxes	2,510	3,060
Deferred tax credits	231	283
Other	2,252	2,045
Total noncurrent liabilities	11,901	13,153
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		
7.90%, 12,000,000 shares due 2025	300	300
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable—5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable—4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 321,314,760 and 341,353,455 shares, respectively	1,606	1,707
Common stock held by subsidiary, at cost, 7,627,765 shares	(200)	—
Additional paid in capital	1,964	2,087
Reinvested earnings	2,107	2,260
Total stockholders' equity	5,771	6,348
Commitments and Contingencies (Notes 2, 6, 14, and 15)	—	—
Total Liabilities and Stockholders' Equity	$21,470	$22,950

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

Statement of Consolidated Cash Flows
(in millions)

	For the year ended December 31,		
	1999	1998	1997
Cash Flows From Operating Activities			
Net income	$ 788	$ 729	$ 768
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,564	1,438	1,748
Deferred income taxes and tax credits—net	(485)	(257)	(182)
Other deferred charges and noncurrent liabilities	101	31	133
Net effect of changes in operating assets and liabilities:			
Accounts receivable—trade	187	266	(582)
Inventories and prepayments	34	(21)	12
Accounts payable—trade	15	203	(80)
Regulatory balancing accounts payable	305	537	126
Accrued taxes	116	(227)	(62)
Other working capital	(73)	(50)	(128)
Other—net	(352)	(39)	15
Net cash provided by operating activities	2,200	2,610	1,768
Cash Flows From Investing Activities			
Capital expenditures	(1,181)	(1,382)	(1,522)
Proceeds from sale of assets	1,014	501	—
Other—net	234	40	(117)
Net cash used by investing activities	67	(841)	(1,639)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	(219)	668	(681)
Long-term debt issued	—	—	355
Long-term debt matured, redeemed, or repurchased	(672)	(1,413)	(852)
Proceeds from issuance of rate reduction bonds	—	—	2,881
Preferred stock redeemed or repurchased	—	(108)	—
Common stock repurchased	(926)	(1,600)	—
Dividends paid	(440)	(444)	(739)
Other—net	1	(5)	(14)
Net cash provided (used) by financing activities	(2,256)	(2,902)	950
Net Change in Cash and Cash Equivalents	11	(1,133)	1,079
Cash and Cash Equivalents at January 1	90	1,223	144
Cash and Cash Equivalents at December 31	$ 101	$ 90	$ 1,223
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 531	$ 600	$ 547
Income taxes (net of refunds)	1,001	1,115	841

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Pacific Gas and Electric Company

Statement of Consolidated Stockholders' Equity
(in millions, except share amounts)

(in millions)	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings	Total Common Stock Equity	Preferred Stock Without Mandatory Redemption Provisions
Balance December 31, 1996	$2,018	$ 3,710	—	$2,636	$ 8,364	$ 402
Net income				768	768	
Holding company formation		(1,146)			(1,146)	
Cash dividends declared						
Preferred stock				(33)	(33)	
Common stock				(699)	(699)	
Other				(1)	(1)	
Balance December 31, 1997	$2,018	$ 2,564	—	$2,671	$ 7,253	$ 402
Net income				729	729	
Common stock repurchased (62,150,837 shares)	(311)	(481)		(808)	(1,600)	
Preferred stock redeemed (4,323,948 shares)		(7)		(3)	(10)	(98)
Cash dividends declared						
Preferred stock				(28)	(28)	
Common stock				(300)	(300)	
Other		11		(1)	10	(10)
Balance December 31, 1998	$1,707	$ 2,087	—	$2,260	$ 6,054	$ 294
Net income				788	788	
Common stock repurchased (27,666,460 shares)	(101)	(123)	(200)	(502)	(926)	
Cash dividends declared						
Preferred stock				(25)	(25)	
Common stock				(415)	(415)	
Other				1	1	
Balance December 31, 1999	$1,606	$ 1,964	$(200)	$2,107	$ 5,477	$ 294

The accompanying Notes to the Consolidated Financial Statements are an integral part of this statement.

Notes to Consolidated Financial Statements

Note 1: General

Basis of Presentation

PG&E Corporation became the holding company of Pacific Gas and Electric Company (the Utility) on January 1, 1997. Prior to that time, the Utility was the predecessor of PG&E Corporation. Effective with PG&E Corporation's formation, the Utility's interests in its unregulated subsidiaries were transferred to PG&E Corporation.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to 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 PG&E Corporation's wholly owned and controlled subsidiaries. The Utility's consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries. All significant intercompany transactions have been eliminated from the consolidated financial statements. Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the 1999 presentation.

The preparation of financial statements in conformity with generally accepted accounting principles 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. Actual results could differ from these estimates.

Accounting principles used include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

Operations

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. Its businesses provide energy services throughout North America. PG&E Corporation's Northern and Central California utility subsidiary, Pacific Gas and Electric Company, provides natural gas and electric service to one of every 20 Americans.

PG&E Corporation's National Energy Group provides energy products and services throughout North America. The National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC (formerly U.S. Generating Company, LLC) and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and in Texas, through various subsidiaries of PG&E Corporation (collectively, PG&E Gas Transmission or PG&E GT); purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the other National Energy Group non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading—Gas Corporation, PG&E Energy Trading—Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET); and provide competitively priced electricity, natural gas, and related services to industrial, commercial, and institutional customers through PG&E Energy Services Corporation (PG&E Energy Services or PG&E ES). In the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's Texas natural gas and natural gas liquids business. Also in the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's retail energy services.

Regulation and Statements of Financial Accounting Standards (SFAS) No. 71

The Utility is regulated by the CPUC, the FERC, and the Nuclear Regulatory Commission, among others. The gas transmission business in the Pacific Northwest is regulated by the FERC. The gas transmission business in Texas is regulated by the Texas Railroad Commission.

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." This statement allows for the deferral as a regulatory asset costs that otherwise would have been expensed if it is probable that the costs will be recovered in future regulated revenues. In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," requires PG&E Corporation and the Utility to write off regulatory assets when they are no longer probable of recovery. On an ongoing basis, PG&E Corporation and the Utility review their regulatory assets and liabilities for the continued applicability of SFAS No. 71 and the effect of SFAS No. 121.

Regulatory assets and liabilities are comprised of the following:

(in millions)	**Balance at December 31, 1999**	**Balance at December 31, 1998**
Utility:		
Generation-related transition costs[1]	$3,996	$5,355
Unamortized loss, net of gain, on reacquired debt	288	289
Regulatory assets for deferred income tax	295	293
Other, net	316	351
Total Utility	$4,895	$6,288
National Energy Group	62	59
Regulatory assets	$4,957	$6,347
Regulatory liabilities	$ 771	$ 526

(1) See Note 2 of Notes to Consolidated Financial Statements for further discussion.

Regulatory assets and liabilities are amortized over the period that the costs are reflected in regulated revenues. The majority of the Utility's regulatory assets are included in generation-related transition costs. The Utility is amortizing its eligible transition costs, including generation-related regulatory assets, over the transition period in conjunction with the available competitive transition charge (CTC) revenues. During 1999, regulatory assets related to electric industry restructuring decreased by $1,359 million. This decrease reflects the recovery of eligible transition costs of $806 million through amortization and $553 million through the gain on the sale of generating plants.

Revenues and Regulatory Balancing Accounts

In connection with electric industry restructuring, use of the Utility's sales and energy cost balancing accounts for electric utility revenues was discontinued in 1998. These balancing accounts have been replaced with regulatory adjustment mechanisms that impact expenses instead of revenues. (See Note 2.) For gas utility revenues, sales balancing accounts accumulate differences between authorized and actual base revenues. Further, gas cost balancing accounts accumulate differences between the actual cost of gas and the revenues designated for recovery of such costs. The regulatory balancing accounts accumulate balances until they are refunded to or received from Utility customers through authorized rate adjustments. Utility revenues included amounts for services rendered but unbilled at the end of each year.

Accounting for Price Risk Management Activities

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both non-hedging and hedging purposes. PG&E Corporation conducts non-hedging activities principally through its unregulated subsidiary, PG&E ET. Derivative and other financial instruments associated with our electric power, natural gas, natural gas liquids, and related non-hedging activities are accounted for using the mark-to-market method of accounting.

Under mark-to-market accounting, PG&E Corporation's non-hedging contracts, including both physical contracts and financial instruments, are recorded at market value, which approximates fair value. The market prices used to value these transactions reflect management's best estimates considering various factors including market quotes, time value, and volatility factors of the underlying commitments. The values are adjusted to reflect the potential impact of liquidating a position in an orderly manner over a reasonable period of time under present market conditions.

Changes in the market value of these contract portfolios, resulting primarily from newly originated transactions and the impact of commodity price and interest rate movements, are recognized in operating revenues in the period of change. Unrealized gains and losses of these contract portfolios are recorded as assets and liabilities, respectively, from price risk management.

In addition to the non-hedging activities discussed above, PG&E Corporation may engage in hedging activities using futures, forward contracts, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies when there is a high degree of correlation between price movements in the derivative and the item designated as being hedged. PG&E Corporation accounts for hedge transactions under the deferral method. Initially, PG&E Corporation defers unrealized gains and losses on these transactions and classifies them as assets or liabilities. When the hedged transaction occurs, PG&E Corporation recognizes the gain or loss in operating expense. In instances where the anticipated correlation of price movements does not occur, hedge accounting is terminated and future changes in the value of the derivative are recognized as gains or losses. If the hedged item is sold, the value of the associated derivative is recognized in income.

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 137, "Accounting for Derivative Instruments and Hedging Activities—Deferral of the Effective Date of FASB Statement No. 133," which delayed the implementation of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," by one year to require adoption in years beginning after June 15, 2000. The Statement permits early adoption as of the beginning of any fiscal quarter.

PG&E Corporation expects to adopt SFAS No. 133 no later than January 1, 2001. The Statement will require PG&E Corporation to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. We currently are evaluating what effect of SFAS No. 133 will be on the earnings and financial position of PG&E Corporation. However, we already use the mark-to-market method of accounting for our commodity non-hedging and price risk management activities.

In compliance with regulatory requirements, the Utility manages price risk independently from the activities in PG&E Corporation's unregulated business. During 1998, the CPUC authorized Pacific Gas and Electric Company to trade natural gas-based financial instruments to manage price and revenue risks associated with its natural gas transmission and storage assets, subject to certain conditions. Also in 1998, the CPUC authorized the Utility to trade natural gas-based financial instruments to hedge the gas commodity price swings in serving core gas customers. In May 1999, the Power Exchange (PX) obtained FERC approval to operate the "block forward market" which offers parties the ability to buy and sell contracts to purchase electricity in the future at prices set in the contracts. The Utility sought and obtained CPUC authority to participate in the PX block forward market for contracts that call for delivery of the purchased electricity by October 31, 2000, as well as to recover costs (such as gains/losses and transaction fees) associated with its participation in this market.

Property, Plant, and Equipment

Plant additions and replacements are capitalized. The capitalized costs include labor, materials, construction overhead, and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions. The Utility recovers AFUDC in rates through depreciation expense over the useful life of the related asset. Nuclear fuel inventories are included in property, plant, and equipment. Stored nuclear fuel inventory is stated at lower of average cost or market. Nuclear fuel in the reactor is amortized based on the amount of energy output.

The original cost of retired plant and removal costs less salvage value is charged to accumulated depreciation upon retirement of plant in service for the Utility and the National Energy Group businesses that apply SFAS No. 71. For the remainder of our National Energy Group business operations, the cost and accumulated depreciation of property, plant, and equipment retired or otherwise disposed of are removed from related accounts and included in the determination of the gain or loss on disposition.

Property, plant, and equipment is depreciated using a straight-line remaining-life method. PG&E Corporation's composite depreciation rates were 3.60 percent, 3.89 percent, and 3.45 percent for the years ended December 31, 1999, 1998, and 1997, respectively. The Utility's composite depreciation rates were 3.41 percent, 3.88 percent, and 3.26 percent for the years ended December 31, 1999, 1998, and 1997, respectively.

Gains and Losses on Reacquired Debt

Any gains and losses on reacquired debt associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original lives of the debt reacquired, consistent with ratemaking principles. Gains and losses on reacquired debt associated with unregulated operations are recognized in earnings at the time such debt is reacquired.

Inventories

Inventories include material and supplies, gas stored underground, coal, and fuel oil. Materials and supplies, coal, and gas stored underground are valued at average cost. Fuel oil is valued by the last-in first-out method.

Cash Equivalents and Short-Term Investments

Cash equivalents (stated at cost, which approximates market) include working funds and consist primarily of Eurodollar time deposits, bankers acceptances, and some commercial paper with original maturities of three months or less.

Income Taxes

PG&E Corporation uses the liability method of accounting for income taxes. Income tax expense includes current and deferred income taxes resulting from operations during the year. Tax credits are amortized over the life of the related property.

PG&E Corporation files a consolidated federal income tax return that includes domestic subsidiaries in which its ownership is 80 percent or more. The Utility and various other subsidiaries are parties to a tax-sharing arrangement with PG&E Corporation. PG&E Corporation files consolidated state income tax returns when applicable. The Utility reports taxes on a stand-alone basis.

Related Party Agreements

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services from their parent, PG&E Corporation. Services include the Utility's provision of general and administrative services. The Utility and other subsidiaries receive general and administrative services and financing from PG&E Corporation. Corporate costs, such as administrative costs, interest, and income taxes, are allocated to subsidiaries using a variety of factors, including their share of employees, operating expenses, assets, and other cost causal methods. Also, the Utility purchases gas commodity and transmission services from PG&E ET and transmission services from PG&E GT NW. Intercompany transactions are eliminated in consolidation and no profit results from these transactions. At December 31, 1999, the Utility has a net intercompany payable to affiliates of $207 million, of which $163 million relates to short-term borrowings, including interest. For the years ended December 31, 1999 and 1998, the Utility's significant related party transactions are provided in the table below.

(in millions)	1999	1998
Utility revenues from:		
Administrative services provided to PG&E Corporation	$ 23	$17
Transportation and distribution services provided to PG&E ES	134	—
Gas reservation services provided to PG&E ET	7	1
Other	3	4
Utility expenses from:		
Administrative services received from PG&E Corporation	66	58
Gas commodity and transmission services received from PG&E ET	30	1
Transmission services received from PG&E GT NW	47	49

Cumulative Effect of Change in Accounting Method

Effective January 1, 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls at the National Energy Group. Beginning January 1, 1999, the cost of major maintenance and overhauls, principally at the PG&E Gen business segment, were accounted for as incurred. Previously, the estimated cost of major maintenance and overhauls was accrued in advance in a systematic and rational manner over the period between major maintenance and overhauls. The change resulted in PG&E Corporation recording income of $12 million net of income tax ($0.03 per share), reflecting the cumulative effect of the change in accounting principle. The effect on current year results of operations was immaterial. Accordingly, the unaudited quarterly consolidated information has been restated. (See "Quarterly Consolidated Financial Data (Unaudited)" below.)

The Utility has consistently accounted for major maintenance and overhauls as incurred.

Note 2: The California Electric Industry

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a competitive market framework for electric generation. Today, most Californians may continue to purchase their electricity from investor-owned utilities such as Pacific Gas and Electric Company, or they may choose to purchase electricity from alternative generation providers (such as unregulated power generators and unregulated retail electricity suppliers such as marketers, brokers, and aggregators). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as the Utility, continue to be the generation providers. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including customers who choose an alternative generation provider.

Competitive Market Framework

To create a competitive generation market, a PX and an Independent System Operator (ISO) began operating on March 31, 1998. The PX provides a competitive auction process to establish market clearing prices for electricity in the markets operated by the PX. The ISO schedules delivery of electricity for all market participants. The Utility continues to own and maintain a portion of the transmission system, but the ISO controls the operation of the system. Unless or until the CPUC determines otherwise, the Utility is required to bid or schedule into the PX and ISO markets all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators. Also, the Utility is required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier.

In November 1999, the FERC approved the extension of the ISO's authority to establish price limitations through 2000. The ISO Board increased the applicable price limitation to $750 per megawatt-hour (MWh) on October 1, 1999, but has the option to decrease it to $500 per MWh or make other changes, in view of the FERC's decision. This limits the amount of volatility that occurs in the California electricity market. However, the ISO will review the appropriate level for any price limitations for the summer of 2000 in light of market redesign efforts now being considered, including changes to reduce uninstructed deviations from ISO dispatch orders and changes to permit loads to participate by submitting bids for price responsive demand in energy or ancillary services markets.

For the year ended December 31, 1999, and for the period of March 31, 1998 (the PX's establishment date) to December 31, 1998, the cost of electric energy for the Utility, reflected on the Statement of Consolidated Income, is comprised of the cost of PX purchases, ancillary services purchased from the ISO, cost of transmission, and the cost of Utility generation, net of sales to the PX as follows:

	Year ended December 31,	
(in millions)	**1999**	**1998**
Cost of fuel for electric generation and qualifying facilities (QF) purchases	$1,489	$ 2,030
Cost of purchases from the PX	1,114	723
Cost of ancillary services	630	617
Proceeds from sales to the PX	(822)	(1,049)
Cost of electric energy	$2,411	$ 2,321

Transition Period, Rate Freeze, and Rate Reduction

California's electric industry restructuring established a transition period during which electric rates remain frozen at 1996 levels (with the exception that, on January 1, 1998, rates for small commercial and residential customers were reduced by 10 percent and remain frozen at this reduced level) and investor-owned utilities may recover their transition costs. Transition costs are generation-related costs that prove to be uneconomic under the new competitive structure. The transition period ends the earlier of December 31, 2001, or when the particular utility has recovered its eligible transition costs.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, nuclear decommissioning, and rate reduction bond debt service. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the CTC, which recovers the transition costs. These CTC revenues are being recovered from all Utility distribution customers and are subject to seasonal fluctuations in the Utility's sales volumes and certain other factors. As the CTC is collected regardless of the customer's choice of electricity supplier (i.e., the CTC is non-bypassable), the Utility believes that the availability of choice to its customers will not have a material impact on its ability to recover transition costs.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service will not increase Utility customers' electric rates. If the transition period ends before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Transition Cost Recovery

Although most transition costs must be recovered during the transition period, certain transition costs can be recovered after the transition period. Except for certain transition costs discussed below, at the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues.

Transition costs consist of (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and that were included in customers' rates on December 20, 1995) and future sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from qualifying facilities and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods, to be included in rates in subsequent periods.)

Above-market sunk costs result when the book value of a facility exceeds its market value. Conversely, below-market sunk costs result when the market value of a facility exceeds its book value. The total amount of generation facility costs to be included as transition costs is based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. These above- and below-market sunk costs are related to generating facilities that are classified as either non-nuclear or nuclear sunk costs.

The Utility cannot determine the exact amount of above-market non-nuclear sunk costs that will be recoverable as transition costs until the valuation of the Utility's remaining non-nuclear generating assets, primarily its hydroelectric generating assets, is completed. The valuation, through appraisal, sale, or other divestiture, must be completed by December 31, 2001. The value of seven of the Utility's other non-nuclear generating facilities was determined when these facilities were sold to third parties. The portion of the sales proceeds that exceeded the book value of these facilities was used to reduce other transition costs. On September 30, 1999, the Utility filed an application with the CPUC to determine the market value of its hydroelectric generating facilities and related assets through an open, competitive auction. (See "Generation Divestiture" below.) The Utility plans to use an auction process similar to the one previously approved by the CPUC and successfully used in the sale of the Utility's fossil and geothermal plants. If the market value of the Utility's hydroelectric facilities is determined based upon any method other than a sale of the facilities to a third party, a material charge to Utility earnings could result. Any excess of market value over book value would be used to reduce other transition costs. (See "Generation Divestiture" below.)

For nuclear transition costs, revenues provided for transition cost recovery are based on the accelerated recovery of the investment in Diablo Canyon Nuclear Power Plant (Diablo Canyon) over a five-year period ending December 31, 2001. The amount of nuclear generation sunk costs was determined separately through a CPUC proceeding and was subject to a final verification audit that was completed in August 1998. The audit of the Utility's Diablo Canyon accounts at December 31, 1996, resulted in the issuance of an unqualified opinion. The audit verified that Diablo Canyon sunk costs at December 31, 1996, were $3.3 billion of the total $7.1 billion construction costs. The independent accounting firm also issued an agreed-upon special procedures report, requested by the CPUC, that questioned $200 million of the $3.3 billion sunk costs. The CPUC will review the results of the audit and may seek to make adjustments to Diablo Canyon's sunk costs subject to transition cost recovery. At this time, the Utility cannot predict what actions, if any, the CPUC may take regarding the audit report.

Costs associated with the Utility's long-term contracts to purchase electric power are included as transition costs. Regulation required the Utility to enter into such long-term agreements with non-utility generators. Prices fixed under these contracts are now typically above prices for power in wholesale markets (See Note 14). Over the remaining life of these contracts, the Utility estimates that it will purchase 299 million MWh of electric power. To the extent that the individual contract prices are above the market price, the Utility is collecting the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. The contracts expire at various dates through 2028.

The total costs under long-term contracts are based on several variables, including the capacity factors of the related generating facilities and future market prices for electricity. During 1999, the average price paid under the Utility's long-term contracts for electricity was 6.3 cents per kilowatt-hour (kWh). The average cost of electricity purchased at market rates from the PX for the year ended December 31, 1999, was 3.7 cents per kWh. The average cost of electricity purchased at market rates from the PX for the period from March 31, 1998, the PX's establishment date, to December 31, 1998, was 3.2 cents per kWh.

Generation-related regulatory assets and obligations (net generation-related regulatory assets) are included as transition costs. At December 31, 1999 and 1998, the Utility's generation-related net regulatory assets totaled $4 billion and $5.4 billion, respectively.

Certain transition costs can be recovered through a non-bypassable charge to distribution customers after the transition period. These costs include (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, (3) up to $95 million of transition costs to the extent that the recovery of such costs during the transition period was displaced by the recovery of electric industry restructuring implementation costs, and (4) transition costs financed by the rate reduction bonds. Transition costs financed by the issuance of rate reduction bonds will be recovered over the term of the bonds. In addition, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission the nuclear facility. During the rate freeze, the charge for these costs will not increase Utility customers' electric rates. Excluding these exceptions, the Utility will write off any transition costs not recovered during the transition period.

The Utility is amortizing its transition costs, including most generation-related regulatory assets, over the transition period in conjunction with the available CTC revenues. During the transition period, a reduced rate of return on common equity of 6.77 percent applies to all generation assets, including those generation assets reclassified to regulatory assets. Effective January 1, 1998, the Utility started collecting these eligible transition costs through the non-bypassable CTC and generation divestiture. For the years ended December 31, 1999 and 1998, regulatory assets related to electric industry restructuring decreased by $1,359 million and $609 million, respectively, which reflects the recovery of eligible transition costs.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition cost recovery and the amount of transition costs requested for recovery. The CPUC is currently reviewing non-nuclear transition costs amortized during 1998 and the first six months of 1999.

Generation Divestiture

In 1998, the Utility sold three fossil-fueled generation plants for $501 million. These three fossil-fueled plants had a combined book value at the time of the sale of $346 million and had a combined capacity of 2,645 megawatts (MW).

On April 16, 1999, the Utility sold three other fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and had a combined capacity of 3,065 MW.

On May 7, 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and had a combined capacity of 1,224 MW.

The gains from the sale of the fossil-fueled generation plants were used to offset other transition costs. Likewise, the loss from the sale of the complex of geothermal generation facilities is being recovered as a transition cost.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

On September 30, 1999, the Utility filed an application with the CPUC to determine the market value of its hydroelectric generating facilities and related assets through an open, competitive auction. The Utility proposes to use an auction process similar to the one previously approved by the CPUC and successfully used in the sale of the Utility's fossil and geothermal plants. Under the process proposed in the application, another subsidiary of PG&E Corporation, PG&E Gen, would be permitted to participate in the auction on the same basis as other bidders.

The sale of the hydroelectric facilities would be subject to certain conditions, including the transfer or re-issuance of various permits and licenses by the FERC and other agencies. In addition, the FERC must approve assignment of the Utility's Reliability Must Run Contract with the ISO for any facility subject to such contract. Under the proposed purchase and sale agreement, the CPUC's approval of the proposed sale on terms acceptable to the Utility in the Utility's sole discretion is also a condition precedent to the closing of any sale.

On January 13, 2000, a scoping memo and ruling was issued that separates the proceeding into two concurrent phases: one to review the potential environmental impacts of the proposed auction under the California Environmental Quality Act and a second to determine whether the Utility's auction proposal, or some other alternative to the proposal, is in the public interest. The ruling notes that the divestiture and valuation issues can best be considered after the environmental impacts of a change in ownership have been reviewed. Potential bidders will also be able to incorporate the costs of any mitigation measures that may be required into their bids. The ruling sets a procedural schedule which calls for a final decision on the Utility's auction proposal by October 19, 2000, and a final environmental impact report published in November 2000. The ruling also anticipates that a final CPUC decision approving the sale would be issued by May 15, 2001. Finally, the ruling prohibits the Utility from withdrawing its application without express CPUC authority. It is uncertain whether the CPUC will ultimately approve the Utility's auction proposal.

At December 31, 1999, the book value of the Utility's net investment in hydroelectric generation assets was approximately $0.7 billion, excluding approximately $0.5 billion of net investment reclassified as regulatory assets. Any excess of market value over the $0.7 billion book value would be used to reduce transition costs, including the remaining $0.5 billion of regulatory assets related to the hydroelectric generation assets. If the market value of the hydroelectric generation assets is determined by any method other than a sale of the assets to a third party, or if the winning bidder for any of the auctioned assets is PG&E Gen, a material charge to Utility earnings could result. The timing and nature of any such charge is dependent upon the valuation method and procedure adopted, and the method of implementation. As discussed below, it is possible that the CPUC will require an interim valuation through an estimate of market value of the assets prior to transfer, sale or other divestiture, which could also result in a material charge. While transfer or sale to an affiliated entity such as PG&E Gen would result in a material charge to income, neither PG&E Corporation nor the Utility believes that the sale of any generation facilities to a third party will have a material impact on its results of operations.

The Utility's ability to continue recovering its transition costs depends on several factors, including (1) the continued application of the regulatory framework established by the CPUC and state legislation, (2) the amount of transition costs ultimately approved for recovery by the CPUC, (3) the determined value of the Utility's hydroelectric generation facilities, (4) future Utility sales levels, (5) future Utility fuel and operating costs, and

(6) the market price of electricity. Given the current evaluation of these factors, PG&E Corporation believes that the Utility will recover its transition costs. However, a change in one or more of these factors could affect the probability of recovery of transition costs and result in a material charge.

Post-Transition Period

In October 1999, the CPUC issued a decision in the Utility's post-transition period ratemaking proceeding. Among other matters, the CPUC's decision addresses the mechanisms for ending the current electric rate freeze and for establishing post-transition period accounting mechanisms and rates. The decision requires Diablo Canyon generation to be priced at prevailing market rates after the transition period.

The CPUC decision requires the Utility to provide quarterly forecasts of when the Utility's rate freeze (i.e., transition period) may end based on various assumptions regarding energy prices and the book value of the Utility's remaining generation assets. The Utility is required to notify the CPUC three months before the earliest forecasted end of its rate freeze and provide draft tariff language and sample calculations of the rates that would go into effect when the rate freeze ends. After the Utility completes its transition cost recovery, it must implement its post-rate-freeze rates.

The timing of the end of the rate freeze and corresponding transition period will, in part, depend on the timing of the valuation of the Utility's hydroelectric generating assets and the ultimate determined value of such assets since any excess of market value over the assets' book value would be used to reduce transition costs. If the value of the Utility's hydroelectric generation assets is significantly higher than the related book value, the transition period and the rate freeze could end before December 31, 2001, and potentially could end during 2000. The CPUC is considering the Utility's proposal to auction its hydroelectric assets, although the CPUC could also require the Utility to implement an interim valuation of the assets. In another proceeding (the 1998 Annual Transition Cost Proceeding (ATCP)), a CPUC administrative law judge issued a proposed decision on January 7, 2000, which contained a proposed change to the rules previously in place for the amortization of transition costs. Under the final decision, issued on February 17, 2000, on a prospective basis the utilities are required to assess the estimated market value of their remaining non-nuclear generating assets, including the land associated with those assets, on an aggregate basis at a value not less than the net book value of those assets and to credit the Transition Cost Balancing Account (TCBA) with the estimated value. The decision encourages the utilities to base such estimates on realistic assessments of the market value of the assets. The final decision did not adopt the proposed decision's recommendation to establish a new regulatory asset account that would allow a true-up when the estimated market value is greater than actual market value. However, the decision states that crediting the TCBA with the aggregate net book value of the remaining non-nuclear generating assets is a conservative approach and remedies any concerns regarding the lack of a true-up. The decision provides that if the estimated market valuation is less than book value for any individual asset, accelerated amortization of the associated transition costs will continue until final market valuation of the asset occurs through sale, appraisal, or other divestiture. If the final value of the assets, determined through sale, appraisal, or other divestiture, is higher than the estimate, the excess amount would be used to pay remaining transition costs, if any. The utilities are required to file the adjusted entries to their respective TCBA based on the estimated market values with the CPUC by March 9, 2000. The filing will become effective after appropriate review by the CPUC's Energy Division and the TCBA entries are subject to review in the next ATCP. If an estimate of the market value of the non-nuclear generating assets is adopted that exceeds the aggregate net book value of those assets, a charge to earnings would result.

After the rate freeze and transition periods end, the Utility must refund to electric customers any over-collected transition costs (plus interest at the Utility's authorized rate of return) within one year after the end of the rate freeze. The Utility also will be prohibited from collecting after the rate freeze any electric costs incurred during the rate freeze but not recovered during the rate freeze, including costs that are not classified as transition costs. Through the end of its rate freeze, the Utility will continue to incur certain non-transition costs and place those costs into balancing and memorandum accounts for future recovery. There is a risk that the Utility will be unable to collect certain non-transition costs that, due to lags in the regulatory cost approval process, have not been approved for recovery nor collected when the rate freeze ends. The Utility is unable to predict the amount of such potential unrecoverable costs.

The CPUC also has established the Purchased Electric Commodity Account for the Utility to track energy costs after the rate freeze and transition period end. The CPUC intends to explore other ratemaking issues, including whether dollar-for-dollar recovery of energy costs is appropriate, in the second phase of the post-transition electric ratemaking proceeding. There are three primary options for the future regulatory framework for utility electric energy procurement cost recovery after the rate freeze: (1) a CPUC-defined procurement practice, that if followed by the Utility, would pass through costs without the need for reasonableness reviews, (2) a pass-through of costs subject to after-the-fact reasonableness reviews, or (3) a procurement incentive mechanism with rewards and penalties determined based on the Utility's energy purchasing performance compared to a benchmark. The Utility proposed adoption of either a defined procurement practice or a procurement incentive mechanism, neither of which would involve reasonableness reviews. The volatility of earnings and risk exposure of the Utility related to post-transition period purchases of electricity is dependent on which of these options, or some other approach, is adopted.

After the transition period, the Utility's future earnings from its electric distribution will be subject to volatility as a result of sales fluctuations.

Note 3: Price Risk Management and Financial Instruments

The following table is a summary of the contract or notional amounts and maturities of PG&E Corporation's contracts used for non-hedging activities related to commodity price risk management as of December 31, 1999 and 1998. Short and long positions pertaining to derivative contracts used for hedging activities as of December 31, 1999 and 1998, are immaterial.

Natural Gas, Electricity, and Natural Gas Liquids Contracts (billions of MMBtu equivalents(1))	**Purchase (Long)**	**Sale (Short)**	**Maximum Term in Years**
Non-Hedging Activities—December 31, 1999			
Swaps	2.28	2.20	7
Options	0.93	0.85	8
Futures	0.19	0.18	2
Forward contracts	1.47	1.42	12
Non-Hedging Activities—December 31, 1998			
Swaps	6.21	6.06	8
Options	1.50	1.28	5
Futures	0.58	0.61	4
Forward contracts	3.70	3.55	5

(1) One MMBtu is equal to one million British thermal units. PG&E Corporation's electric power contracts, measured in megawatts, were converted to MMBtu equivalents using a conversion factor of 10 MMBtu's per 1 megawatt-hour. PG&E Corporation's natural gas liquids contracts were converted to MMBtu equivalents using an appropriate conversion factor for each type of natural gas liquids product.

Volumes shown for swaps, futures, and options represent notional volumes that are used to calculate amounts due under the agreements and do not necessarily represent volumes exchanged. Moreover, notional amounts are indicative only of the volume of activity and are not a measure of market risk.

PG&E Corporation's net gains (losses) on swaps, options, futures, and forward contracts held during the years ended December 31, 1999 and 1998 are as follows:

	Year ended December 31,	
(in millions)	**1999**	**1998**
Swaps	$ 15	$ 69
Options	(41)	(49)
Futures	(36)	(63)
Forward contracts	98	101
Net gain (loss)	$ 36	$ 58

The following table discloses the estimated fair values of price risk management assets and liabilities as of December 31, 1999 and 1998. The ending and average fair values and associated carrying amounts of derivative contracts used for hedging purposes are not material as of December 31, 1999 and 1998.

(in millions)	Average Fair Value	Ending Fair Value
Non-Hedging Activities—December 31, 1999		
Assets:		
Swaps	$ 643	$ 244
Options	106	92
Futures	175	47
Forward contracts	667	596
Total	$1,591	$ 979
Noncurrent portion		$ 372
Current portion		$ 607
Liabilities:		
Swaps	$ 592	$ 218
Options	109	81
Futures	201	67
Forward contracts	561	456
Total	$1,463	$ 822
Noncurrent portion		$ 247
Current portion		$ 575
Non-Hedging Activities—December 31, 1998		
Assets:		
Swaps	$ 494	$ 947
Options	121	154
Futures	115	150
Forward contracts	342	499
Total	$1,072	$1,750
Noncurrent portion		$ 334
Current portion		$1,416
Liabilities:		
Swaps	$ 476	$ 908
Options	147	201
Futures	111	186
Forward contracts	282	398
Total	$1,016	$1,693
Noncurrent portion		$ 281
Current portion		$1,412

PG&E Corporation, primarily through its subsidiaries, engages in price risk management activities for both non-hedging and hedging purposes. Non-hedging activities are conducted principally through its unregulated subsidiary, PG&E ET. In compliance with regulatory requirements, the Utility manages price risk independently from the activities in PG&E Corporation's unregulated businesses (see Note 1 for further discussion). The Utility primarily engages in hedging activities which, noted above, were immaterial for the years ended December 31, 1999 and 1998.

In valuing its electric power, natural gas, and natural gas liquids portfolios, PG&E Corporation considers a number of market risks and estimated costs and continuously monitors the valuation of identified risks and adjusts them based on present market conditions. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided herein are not necessarily indicative of the amounts that PG&E Corporation could realize in the current market.

Generally, exchange-traded futures contracts require deposit of margin cash, the amount of which is subject to change based on market movement and in accordance with exchange rules. Margin cash requirements for over-the-counter financial instruments are specified by the particular instrument and often do not require margin cash and are settled monthly. Both exchange-traded and over-the-counter options contracts require payment/receipt of an option premium at the inception of the contract. Margin cash for commodities futures and cash on deposit with counterparties was immaterial at December 31, 1999.

Note 4: Concentrations of Market and Credit Risk

Market Risk

Market risk is the risk that changes in market prices will adversely affect earnings and cash flows. PG&E Corporation is primarily exposed to the market risk associated with energy commodities such as electric power, natural gas, and natural gas liquids. Therefore, PG&E Corporation's price risk management activities primarily involve buying and selling fixed-price commodity commitments into the future. Net open positions often exist or are established due to PG&E Corporation's assessment of and response to changing market conditions. To the extent that PG&E Corporation has an open position, it is exposed to the risk that fluctuating market prices may adversely impact its financial results.

Credit Risk

The use of financial instruments to manage the risks associated with changes in energy commodity prices creates exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligation. The counterparties in PG&E Corporation's portfolio consist primarily of investor-owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies. PG&E Corporation minimizes credit risk by dealing primarily with creditworthy counterparties in accordance with established credit approval practices and limits. PG&E Corporation routinely assesses the financial strength of its counterparties and may require letters of credit or parental guarantees when the financial strength of a counterparty is not considered sufficient. PG&E Corporation has experienced no material losses due to the nonperformance of counterparties in 1999. The credit exposure of the five largest counterparties comprised approximately $250 million of the total credit exposure associated with financial instruments used to manage price risk. Counterparties considered to be investment grade or higher comprise 70 percent of the total credit exposure.

Note 5: Acquisitions and Sales

In January 1997, PG&E Corporation acquired Teco Pipeline Company for $378 million, consisting of $317 million of PG&E Corporation common stock and the purchase of a $61 million note.

In April 1997, through one of its wholly owned subsidiaries, PG&E Corporation sold its interest in International Generating Company, Ltd., which resulted in an after-tax gain of approximately $120 million.

In July 1997, PG&E Corporation completed its acquisition of Valero Energy Corporation's natural gas business and a gas marketing business located in Texas. PG&E Corporation issued approximately 31 million shares of its common stock to acquire Valero along with the assumption of $780 million in long-term debt, equating to a purchase price of approximately $1.5 billion. The acquisition was accounted for as a purchase and accordingly, the purchase price has been allocated to the assets acquired and the liabilities assumed based on estimated fair values.

In September 1997, PG&E Corporation became the sole owner of PG&E Gen, an independent power developer, owner, and manager; PG&E Operating Services Company, PG&E Gen's operations and maintenance affiliate; and USGen Power Services, L.P., PG&E Gen's power marketing affiliate. Additionally, PG&E Corporation has acquired all or part of interest in several power projects that are affiliated with PG&E Gen.

In July 1998, PG&E Corporation sold its Australian energy holdings. The sale represents a premium on the price in local currency of PG&E Corporation's 1996 investment in the assets. However, the transaction resulted in a charge of $.06 per share in the second quarter of 1998. This charge was primarily due to the 22 percent currency devaluation of the Australian dollar against the U.S. dollar during 1998 and 1997.

In September 1998, PG&E Corporation, through its indirect subsidiary USGen New England, Inc. (USGenNE), completed the acquisition of a portfolio of electric generating assets and power supply contracts from the New England Electric System (NEES). The acquisition has been accounted for using the purchase method of accounting. Accordingly, the purchase price has been allocated to the assets purchased and the liabilities assumed based upon an assessment of the fair values at the date of acquisition.

Including fuel and other inventories and transaction costs, PG&E Corporation's financing requirements for this acquisition were approximately $1.8 billion, funded through an aggregate of $1.3 billion PG&E Gen and USGenNE debt and a $425 million equity contribution from PG&E Corporation. The net purchase price has been allocated as follows: (1) electric generating assets of $2.3 billion classified as property, plant, and equipment, (2) receivable for support payments of $0.8 billion, and (3) contractual obligations of $1.3 billion classified as current liabilities and other noncurrent liabilities. The assets include hydroelectric, coal, oil, and natural gas generation facilities with a combined generating capacity of 4,000 MW. In addition, USGenNE assumed 23 multi-year power purchase agreements representing an additional 800 MW of production capacity. USGenNE entered into agreements with NEES as part of the acquisition, which (1) provide that NEES shall make support payments over the next 9 years to USGenNE for the purchase power agreements, and (2) require that USGenNE provide electricity to certain of NEES affiliates under contracts that expire over the next 3 to 10 years.

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E ES, its wholly owned subsidiary, through a sale. As of December 31, 1999, the intended disposal has been accounted for as a discontinued operation. In connection with this transaction, PG&E Corporation's investment in PG&E ES was written down to its estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million. While there is no definite sales agreement, it is expected that the disposition will be completed in 2000. The amounts that PG&E Corporation will ultimately realize from this disposal could be materially different from the amounts assumed in arriving at the estimated loss on disposal of the discontinued operations. The PG&E ES business segment generated net losses of $40 million (or $0.11 per share), $52 million (or $0.14 per share), and $29 million (or $0.07 per share), for the years ended December 31, 1999, 1998 and 1997, respectively.

The total assets and liabilities, including the charge noted above, of PG&E ES included in the PG&E Corporation Consolidated Balance Sheet at December 31, 1999 and 1998, are as follows:

(in millions)	**Balance at December 31, 1999**	**1998**
Assets		
Current assets	$114	$148
Noncurrent assets	83	54
Total Assets	$197	$202
Liabilities		
Current liabilities	$ 61	$ 72
Noncurrent liabilities	10	9
Total liabilities	71	81
Net assets	126	121

On January 27, 2000, PG&E Corporation's National Energy Group signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. (collectively, PG&E GTT). The consideration to be received by the National Energy Group includes $279 million in cash subject to a working capital adjustment, the assumption by El Paso of debt having a book value of $624 million, and other liabilities associated with PG&E GTT.

In 1999, PG&E Corporation recognized a charge against earnings of $890 million after-tax, or $2.42 per share, to reflect PG&E GTT's assets at their fair market value. The composition of the pre-tax charge is as follows: (1) an $819 million write down of net property, plant, and equipment, (2) the elimination of the unamortized portion of goodwill, in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

Proceeds from the sale will be used to retire short-term debt associated with PG&E GTT's operations and for other corporate purposes. Closing of the sale, which is expected in the first half of 2000, is subject to approval under the Hart Scott Rodino Act.

The sale of PG&E GTT represents disposal of the PG&E GTT business segment and a portion of the PG&E ET business segment. PG&E GTT's total assets and liabilities, including the charge noted above, included in the PG&E Corporation Consolidated Balance Sheet at December 31, 1999 and 1998, are as follows:

(in millions)	Balance at December 31, 1999	1998
Assets		
Current assets	$ 229	$ 366
Noncurrent assets	988	2,346
Total Assets	$1,217	$2,712
Liabilities		
Current liabilities	$ 448	$ 486
Noncurrent liabilities	624	1,174
Total liabilities	1,072	1,660
Net assets	145	1,052

Note 6: Common Stock

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock of which 384 million and 383 million shares were issued as of December 31, 1999 and 1998, respectively.

During the years ended December 31, 1999 and 1998, PG&E Corporation repurchased $693 million and $1,158 million of its common stock, respectively. The repurchases in 1998 and through September 1999 were executed through separate, accelerated share repurchase programs. Under the 1999 agreement, PG&E Corporation repurchased in a specific transaction 16.6 million shares of its common stock at a cost of $502 million. In connection with this transaction, PG&E Corporation entered into a forward contract with an investment institution. PG&E Corporation settled the forward contract and its additional obligation of $29 million in September 1999. A wholly owned subsidiary of PG&E Corporation made this repurchase, along with subsequent stock repurchases. The stock held by the subsidiary is treated as treasury stock and reflected as stock held by subsidiary on the Consolidated Balance Sheet of PG&E Corporation.

In October 1999, the Board of Directors of PG&E Corporation authorized an additional $500 million for the purpose of repurchasing shares of the Corporation's common stock on the open market. This authorization supplements the approximately $40 million remaining from the amount previously authorized by the Board of Directors on December 17, 1997. The authorization for share repurchase extends through September 30, 2001. As of December 31, 1999, a subsidiary of PG&E Corporation has repurchased 7.2 million shares at a cost of $159 million under this authorization.

Utility

All of the Utility's outstanding common stock is held by PG&E Corporation and a subsidiary of the Utility. In connection with the formation of the holding company, all of the Utility's then-outstanding common stock was converted on a share-for-share basis to PG&E Corporation common stock.

The Utility has authorized 800 million shares of $5 par value common stock of which 321 million and 341 million shares were issued as of December 31, 1999 and 1998, respectively.

Prior to December 1999, the Utility repurchased 20 million shares of its common stock from PG&E Corporation for an aggregate purchase price of $726 million to maintain its authorized capital structure. In December 1999, 7.6 million shares of the Utility's common stock, with an aggregate purchase price of $200 million, was purchased by a subsidiary of the Utility. This purchase is reflected as stock held by subsidiary in the Consolidated Balance Sheet of Pacific Gas and Electric Company.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. In 1999, the Utility was in compliance with its CPUC-authorized capital structure.

Note 7: Preferred Stock and Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

Preferred Stock of Utility

The Utility has authorized 75 million shares of $25 par value preferred stock which may be issued as redeemable or nonredeemable preferred stock. At December 31, 1999 and 1998, the Utility had issued and outstanding 5,784,825 shares of nonredeemable preferred stock.

At December 31, 1999 and 1998, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share at December 31, 1999, range from $1.09 to $1.76 and from $25.75 to $27.25, respectively. In 1998, the Utility redeemed its Series 7.44% preferred stock with a face value of $65 million. Also in 1998, the Utility redeemed its Series 6⅞% preferred stock with a face value of $43 million.

The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57% series and 2.5 million shares of the 6.30% series at December 31, 1999. The 6.57% series and 6.30% series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding.

Holders of the Utility's nonredeemable preferred stock 5%, 5.5%, and 6% series have rights to annual dividends per share ranging from $1.25 to $1.50.

Dividends on all preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

Preferred Stock of the National Energy Group

Preferred stock of the National Energy Group consists of $57 million of preferred stock issued by a subsidiary of PG&E Gen. The preferred stock, with $100 par value, has a stated dividend of $3.35 per share, per quarter, and is redeemable when there is an excess of available cash. There were 549,594 shares outstanding at December 31, 1999 and 1998.

Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures

The Utility, through its wholly owned subsidiary, PG&E Capital I (Trust), has outstanding 12 million shares of 7.90% cumulative quarterly income preferred securities (QUIPS), with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of $9 million. The Trust in turn used the net proceeds from the QUIPS offering and issuance of the common stock securities to purchase subordinated debentures issued by the Utility with a face value of $309 million, an interest rate of 7.9%, and a maturity date of 2025. These subordinated debentures are the only assets of the Trust. Proceeds from the sale of the subordinated debentures were used to redeem and repurchase higher-cost preferred stock.

The Utility's guarantee of the QUIPS, considered together with the other obligations of the Utility with respect to the QUIPS, constitutes a full and unconditional guarantee by the Utility of the Trust's contractual obligations under the QUIPS issued by the Trust. The subordinated debentures may be redeemed at the Utility's option beginning in 2000 at par value plus accrued interest through the redemption date. The proceeds of any redemption will be used by the Trust to redeem QUIPS in accordance with their terms.

Upon liquidation or dissolution of the Utility, holders of these QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment.

Note 8: Long-Term Debt

Long-term debt at December 31, 1999 and 1998, consisted of the following:

(in millions)			Balance at December 31, 1999	1998
Utility long-term debt				
First and refunding mortgage bonds				
	Maturity	Interest rates		
	2000-2003	6.25% to 8.75%	$ 816	$ 969
	2004-2008	5.875% to 6.25%	600	615
	2009-2021	6.35% to 7.59%	160	160
	2022-2026	5.85% to 8.80%	2,004	2,117
	Principal amounts outstanding		3,580	3,861
	Unamortized discount net of premium		(29)	(32)
Total mortgage bonds			3,551	3,829
Pollution control loan agreements, variable rates, due 2010-2026			1,348	1,348
Unsecured medium-term notes, 5.56% to 8.45%, Due 2000-2014			418	498
Other Utility long-term debt			25	29
Total Utility long-term debt			5,342	5,704
Current portion of long-term debt			465	260
Total Utility long-term debt, net of current portion			4,877	5,444
National Energy Group long-term debt				
First mortgage notes, 10.02% to 11.50%, due 2000-2009			333	370
Senior notes				
	Maturity	Interest rates		
	1999	10.58%	—	69
	2005	7.10%	250	250
Medium-term notes, 6.61% to 9.25%, due 2000-2012			299	298
Senior debentures, 7.80%, due 2025			150	150
Amounts outstanding under credit facilities (See Note 10)			649	654
Other long-term debt			242	265
Total National Energy Group long-term debt			1,923	2,056
Current portion of long-term debt			127	78
Total National Energy Group long-term debt, net of current portion			1,796	1,978
Total long-term debt			$6,673	$7,422

Utility

First and Refunding Mortgage Bonds:

First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.85 percent to 8.80 percent. All real properties and substantially all personal properties of the Utility are subject to the lien of the bonds, and the Utility is required to make semi-annual sinking fund payments for the retirement of the bonds. Additional bonds may be issued subject to CPUC approval, up to a maximum total amount outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and available property balances as security.

The Utility redeemed or repurchased $281 million and $501 million of the bonds in 1999 and 1998, respectively, with interest rates ranging from 6.25 percent to 8.80 percent. These bonds were to mature from 2002 to 2026.

Included in the total of outstanding bonds at December 31, 1999 and 1998, are $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 percent to 6.625 percent and maturity dates ranging from 2009 to 2023. In addition to these bonds, the Utility holds long-term pollution control loan agreements with the CPCFA as described below.

Pollution Control Loan Agreements:

Pollution control loan agreements from the CPCFA totaled $1,348 million at December 31, 1999 and 1998. Interest rates on the loans vary with average annual interest rates. For 1999 the interest rates ranged from 2.36 percent to 3.39 percent. These loans are subject to redemption by the holder under certain circumstances. These loans are secured primarily by irrevocable letters of credit which mature in 2000 through 2003.

National Energy Group

Long-term debt of the National Energy Group consists of first mortgage bonds and other secured and unsecured obligations.

The first mortgage notes are comprised of three series due annually through 2009, and are secured by mortgages and security interests in the natural gas transmission and natural gas processing facilities and other real and personal property of PG&E GTT. The mortgage indenture requires semi-annual payments with one-half of each interest payment and one-fourth of each annual principal payment escrowed quarterly in advance. The mortgage indenture also contains covenants that restrict the ability of PG&E GTT to incur additional indebtedness and precludes cash distributions if certain cash flow coverages are not met. In January 2000, PG&E GTT obtained an amendment that provides PG&E GTT the ability to redeem in whole or in part, its Mortgage Notes, including the premium set forth in the Mortgage Note Indenture, anytime after January 1, 2000. These notes will be assumed by the buyer of PG&E GTT (see Note 5).

Other long-term debt consists of project financing associated with unregulated generation facilities, premiums, and other loans.

Repayment Schedule

At December 31, 1999, PG&E Corporation's combined aggregate amounts of maturing long-term debt and sinking fund requirements, for the years 2000 through 2004, are $592 million, $480 million, $1,363 million, $1,271 million, and $470 million, respectively. The Utility's share of those maturities and sinking fund requirements is $465 million, $374 million, $1,117 million, $664 million, and $392 million, respectively.

Note 9: Rate Reduction Bonds

In December 1997, PG&E Funding LLC (SPE), a special-purpose entity wholly owned by the Utility, issued $2.9 billion of rate reduction bonds to the California Infrastructure and Economic Development Bank Special Purpose Trust PG&E-1 (Trust), a special-purpose entity. The terms of the bonds generally mirror the terms of the pass-through certificates issued by the Trust. The proceeds of the rate reduction bonds were used by the SPE to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable tariff levied on residential and small commercial customers which was authorized by the CPUC pursuant to state legislation.

The rate reduction bonds have maturities ranging from 6 months to 8 years, and bear interest at rates ranging from 6.15 percent to 6.48 percent. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

At December 31, 1999, $2.3 billion of rate reduction bonds were outstanding. The combined expected principal payments on the rate reduction bonds for the years 2000 through 2004 are $290 million for each year.

While the SPE is consolidated with the Utility for purposes of these financial statements, the SPE is legally separate from the Utility. The assets of the SPE are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation.

Note 10: Credit Facilities

PG&E Corporation

At December 31, 1999 and 1998, PG&E Corporation had borrowed $2,148 million and $2,298 million, respectively, under various credit facilities discussed below. $649 million and $654 million of these borrowings at December 31, 1999 and 1998, respectively, are classified as long-term debt. (See Note 8.) The weighted average interest rate on the short-term borrowings was 5.4 percent and 5.6 percent for 1999 and 1998, respectively.

PG&E Corporation maintains two $500 million revolving credit facilities, one of which expires in November 2000 and the other in 2002. These credit facilities are used to support the commercial paper program and other liquidity needs. The facility expiring in 2000 may be extended annually for additional one-year periods upon agreement with the lending institutions. There was $450 million and $683 million of commercial paper outstanding at December 31, 1999 and 1998, respectively. PG&E Corporation introduced a $200 million Extendible Commercial Note (ECN) program during the third quarter of 1999. The ECN program supplements our short-term borrowing capability. There was $76 million of ECNs outstanding at December 31, 1999, which are not supported by the credit facilities.

Utility

The Utility maintains a $1 billion revolving credit facility which expires in 2002. The facility may be extended annually for additional one-year periods upon agreement with the banks. This facility is used to support the Utility's commercial paper program and other liquidity requirements. The total amount outstanding at December 31, 1999, backed by this facility, was $449 million in commercial paper. The total amount outstanding at December 31, 1998, backed by this facility was $567 million in commercial paper and $101 million of bank notes.

National Energy Group

PG&E Gen maintains two $550 million revolving credit facilities. One facility expires in August 2000 and the other expires in 2003. The amount outstanding at December 31, 1999 and 1998, backed by the facilities, was $898 million and $233 million, respectively in commercial paper. Also outstanding at December 31, 1998, was a $540 million eurodollar loan drawn on one of the revolving credit facilities, which was subsequently paid off in 1999. At December 31, 1999 and 1998, $550 million of these loans is classified as noncurrent in the consolidated balance sheet.

In 1998, USGenNE, a subsidiary of PG&E Gen, established a $100 million revolving credit facility that expires in 2003. No amounts were outstanding at December 31, 1999.

PG&E GT NW maintains a $100 million revolving credit facility that expires in 2002, but has an annual renewal option allowing the facility to maintain a three-year duration. PG&E GT NW also maintains a $50 million 364-day credit facility which expires in 2000, but may be extended for successive 364-day periods. No amounts were outstanding under either of these credit facilities at December 31, 1999. At December 31, 1999 and 1998, PG&E GT NW had an outstanding commercial paper balance of $99 million and $104 million, respectively, which is classified as noncurrent in the Consolidated Balance Sheet of PG&E Corporation.

PG&E GTT maintains four separate credit facilities that total $250 million and are guaranteed by PG&E Corporation. At December 31, 1999, PG&E GTT had $176 million of outstanding short-term bank borrowings related to these credit facilities. At December 31, 1998, PG&E GTT had $70 million of outstanding short-term bank borrowings related to two credit facilities. These lines may be cancelled upon demand and bear interest at each respective bank's quoted money market rate. The borrowings are unsecured and unrestricted as to use.

Note 11: Nuclear Decommissioning

Decommissioning of the Utility's nuclear power plants is scheduled to begin for ratemaking purposes in 2015 with scheduled completion in 2034. Nuclear decommissioning means to safely remove nuclear facilities from service and reduce residual radioactivity to a level that permits termination of the Nuclear Regulatory Commission license and release of the property for unrestricted use.

The estimated total obligation for nuclear decommissioning costs, based on a 1997 site study, is $1.6 billion in 1999 dollars (or $5.1 billion in future dollars). This estimate assumes after-tax earnings on the tax-qualified and non-tax-qualified decommissioning funds of 6.34 percent and 5.39 percent, respectively, as well as a future annual escalation rate of 5.5 percent for decommissioning costs. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, and costs of labor, materials, and equipment. The estimated total obligation is being recognized proportionately over the license term of each facility.

For the year ended December 31, 1999, nuclear decommissioning costs recovered in rates were $26.5 million. For the years ended December 31, 1998 and 1997, nuclear decommissioning costs recovered in rates were $33 million per year, respectively. The CPUC has established a Nuclear Decommissioning Cost Triennial

Proceeding to review, every three years, updated decommissioning cost estimates and to establish the annual trust contribution, absent general rate cases.

At December 31, 1999, the total nuclear decommissioning obligation accrued was $1.3 billion and is included in the balance sheet classification of accumulated depreciation and decommissioning. Decommissioning costs recovered in rates are placed in external trust funds. These funds along with accumulated earnings will be used exclusively for decommissioning and cannot be released from the trust funds until authorized by the CPUC.

The following table provides a summary of fair value, based on quoted market prices, of these nuclear decommissioning funds:

	Year Ended December 31,		
(in millions)	**Maturity Dates**	**1999**	**1998**
U.S. government and agency issues	2000-2030	$ 380	$ 379
Equity securities	—	223	246
Municipal bonds and other	2000-2031	201	164
Gross unrealized holding gains		474	394
Gross unrealized holding losses		(14)	(11)
Fair value (net of tax)		$1,264	$1,172

The proceeds received from sales of securities were $1.7 billion in 1999, and $1.4 billion in 1998 and 1997. The gross realized gains on sales of securities held as available-for-sale were $59 million, $52 million, and $40 million in 1999, 1998, and 1997, respectively. The gross realized losses on sales of securities held as available-for-sale were $60 million, $39 million, and $24 million in 1999, 1998, and 1997, respectively. The cost of debt and equity securities sold is determined by specific identification.

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities. The DOE's current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2006. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2006. The Utility is examining options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities, pending disposal or storage at a DOE facility.

Note 12: Employee Benefit Plans

Several of PG&E Corporation's subsidiaries provide noncontributory defined benefit pension plans for their employees and retirees. In addition, these subsidiaries provide contributory defined benefit medical plans for certain retired employees and their eligible dependents and noncontributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). For both pension and other benefit plans, the Utility's plan represents substantially all of the plan assets and the benefit obligation. Therefore, all descriptions and assumptions are based on the Utility's plans. The schedules below aggregate all of the plans employed by PG&E Corporation's subsidiaries.

The following schedule reconciles the plans' funded status (the difference between fair value of plan assets and the benefit obligation) to the prepaid or accrued benefit cost recorded on the consolidated balance sheet as of and for the years ended December 31, 1999 and 1998:

(in millions)	Pension Benefits 1999	Pension Benefits 1998	Other Benefits 1999	Other Benefits 1998
Change in benefit obligation				
Benefit obligation at January 1	$(4,977)	$(4,457)	$ (949)	$(907)
Service cost for benefits earned	(121)	(108)	(19)	(19)
Interest cost	(347)	(333)	(69)	(64)
Actuarial gain (loss)	372	(321)	(19)	(36)
Adopted plan benefits	—	—	(4)	—
Participant paid benefits	—	—	(14)	—
Benefits and expenses paid	266	242	104	77
Benefit obligation at December 31	(4,807)	(4,977)	(970)	(949)
Change in plan assets				
Fair value of plan assets at January 1	7,104	6,419	951	823
Actual return on plan assets	1,331	919	240	173
Company contributions	4	27	15	18
Participant paid benefits	—	—	14	13
Benefits and expenses paid	(286)	(261)	(103)	(76)
Fair value of plan assets at December 31	8,153	7,104	1,117	951
Plan assets in excess of benefit obligation	3,346	2,127	147	2
(Benefit obligation in excess of plan assets)				
Unrecognized prior service cost	93	104	17	19
Unrecognized net loss (gain)	(2,963)	(2,025)	(546)	(430)
Unrecognized net transition obligation	65	79	339	366
Prepaid (accrued) benefit cost	$ 541	$ 285	$ (43)	$ (43)

The Utility's share of the plans' assets in excess of the benefit obligation for pensions in 1999 and 1998 was $3,344 million and $2,134 million, respectively. The Utility's share of the prepaid benefit cost for the pensions in 1999 and 1998 was $556 million and $301 million, respectively.

The plan assets of the Utility exceeded its share of the benefit obligation for other benefits by $167 million and $24 million in 1999 and 1998, respectively. The Utility's share of the accrued benefit liability for other benefits in 1999 and 1998 was $22 million and $26 million, respectively.

Unrecognized prior service costs and the net gains are amortized on a straight-line basis over the average remaining service period of active plan participants. The transition obligations for pension benefits and other benefits are being amortized over 17.5 years from 1987.

Net benefit income (cost) was as follows:

December 31, (in millions)	Pension Benefits 1999	Pension Benefits 1998	Pension Benefits 1997	Other Benefits 1999	Other Benefits 1998	Other Benefits 1997
Service cost for benefits earned	$(121)	$(108)	$(102)	$(19)	$(19)	$(21)
Interest cost	(347)	(333)	(316)	(69)	(64)	(64)
Expected return on assets	634	567	486	83	73	60
Amortized prior service and transition cost	(25)	(26)	(22)	(27)	(28)	(28)
Actuarial gain recognized	111	114	74	20	22	13
Benefit income (cost)	$ 252	$ 214	$ 120	$(12)	$(16)	$(40)

The Utility's share of the net benefit income for pensions in 1999, 1998, and 1997 was $253 million, $215 million, and $123 million, respectively.

The Utility's share of the net benefit cost for other benefits in 1999, 1998, and 1997 was $9 million, $12 million, and $38 million, respectively.

Net benefit income (cost) is calculated using an expected long-term rate of return on plan assets of 9.0 percent. The difference between actual and expected long-term rate of return on plan assets is included in net amortization and deferral and is considered in the determination of future net benefit income (cost). In 1999, 1998, and 1997, actual return on plan assets exceeded expected return.

In conformity with SFAS No. 71, regulatory adjustments have been recorded in the income statement and balance sheet of the Utility which reflect the difference between Utility pension income determined for accounting purposes and Utility pension income determined for ratemaking, which is based on a funding approach.

The CPUC also has authorized the Utility to recover the costs associated with its other benefit plans for 1993 and beyond. Recovery is based on the lesser of the annual accounting costs or the annual contributions on a tax-deductible basis to the appropriate trusts.

The following actuarial assumptions were used in determining the plans' funded status and net benefit income (cost). Year-end assumptions are used to compute funded status, while prior year-end assumptions are used to compute net benefit income (cost).

	Pension Benefits			Other Benefits		
December 31,	**1999**	**1998**	**1997**	**1999**	**1998**	**1997**
Discount rate	7.5%	7.0%	7.5%	7.5%	7.0%	7.5%
Average expected rate of future compensation increases	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Expected long-term rate of return on plan assets	8.5%	9.0%	9.0%	9.0%	9.0%	9.0%

The assumed health care cost trend rate for 2000 is approximately 8.5 percent, grading down to an ultimate rate in 2006 of approximately 6.0 percent. The assumed health care cost trend rate can have a significant effect on the amounts reported for health care plans. A one percentage point change would have the following effects:

(in millions)	**1-Percentage Point Increase**	**1-Percentage Point Decrease**
Effect on total service and interest cost components	$ 6	$ (6)
Effect on postretirement benefit obligation	$62	$(57)

Long-term Incentive Program

PG&E Corporation maintains a Long-term Incentive Program (Program) that provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents. As of December 31, 1999, 34,389,230 shares of PG&E Corporation common stock have been authorized for award with 15,779,821 shares still available under this program. Shares granted in 1999, 1998 and 1997, had approximate values of $23 million, $27 million, and $12 million, respectively, using the Black-Scholes valuation method. In addition, PG&E Corporation granted 9,712,900 shares on January 3, 2000 at an option price of $19.8125 and 18,000 shares on February 1, 2000 at an option price of $22.1875, the then-current market prices.

Outstanding stock options become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant and expire ten years and one day after the date of grant. Shares outstanding at December 31, 1999, had option prices ranging from $16.75 to $34.25 and a weighted-average remaining contractual life of 7.8 years. As permitted under SFAS No. 123 "Accounting for Stock-Based Compensation," PG&E Corporation applies Accounting Board Opinion No. 25 in accounting for the program. As the exercise price of all stock options are equal to their fair market value at the time the options are granted, PG&E Corporation does not recognize any compensation expense related to the program using the intrinsic value based method. Had compensation expense been recognized using the fair value based method under SFAS No. 123, PG&E Corporation's consolidated earnings would have been reduced by $16 million, $10 million and $4 million in 1999, 1998, and 1997, respectively.

The following table summarizes the program's activity as of and for the year ended December 31, 1999, 1998 and 1997:

	1999		1998		1997	
(shares in millions)	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding—						
beginning of year	11.1	$28.35	6.2	$26.21	3.5	$29.56
Granted during year	7.0	$30.94	6.4	$30.53	3.0	$22.55
Exercised during year	(0.5)	$25.86	(0.7)	$29.63	(0.2)	$27.36
Cancellations during year	(1.2)	$29.82	(0.8)	$28.16	(0.1)	$27.82
Outstanding-end of year	16.4	$29.43	11.1	$28.35	6.2	$26.21
Exercisable-end of year	3.0	$29.08	2.4	$29.06	1.9	$30.84

Note 13: Income Taxes

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

	PG&E Corporation			Utility		
Year ended December 31, (in millions)	1999	1998	1997	1999	1998	1997
Current	$1,002	$718	$ 725	$1,133	$ 886	$ 791
Deferred	(702)	(51)	(119)	(433)	(201)	(142)
Tax credits, net	(52)	(56)	(41)	(52)	(56)	(40)
Income tax expense	$ 248	$611	$ 565	$ 648	$ 629	$ 609

In 1999, the income tax expense of PG&E Corporation was allocated to continuing operations ($248 million), discontinued operations ($71 million tax benefit), and cumulative effect of a change in an accounting principle ($8 million).

The significant components of net deferred income tax liabilities were:

	PG&E Corporation		Utility	
December 31, (in millions)	1999	1998	1999	1998
Deferred income tax assets:				
Customer advances for construction	$ 109	$ 68	$ 109	$ 68
Unamortized investment tax credits	118	127	118	127
Provision for injuries and damages	185	220	185	220
Deferred contract costs	182	242	—	—
Other	544	562	442	428
Total deferred income tax assets	$1,138	$1,219	$ 854	$ 843
Deferred income tax liabilities:				
Regulatory balancing accounts	(47)	43	(47)	40
Plant in service	2,827	3,722	2,428	2,930
Income tax regulatory asset	297	391	287	381
Other	1,075	968	577	555
Total deferred income tax liabilities	4,152	5,124	3,245	3,906
Total net deferred income taxes	$3,014	$3,905	$2,391	$3,063
Classification of net deferred income taxes:				
Included in current (assets) liabilities	$ (133)	$ 44	$ (119)	$ 3
Included in noncurrent liabilities	3,147	3,861	2,510	3,060
Total net deferred income taxes	$3,014	$3,905	$2,391	$3,063

The differences between income taxes and amounts determined by applying the federal statutory rate to income before income tax expense for continuing operations were:

	PG&E Corporation			Utility		
Year ended December 31,	**1999**	**1998**	**1997**	**1999**	**1998**	**1997**
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)	10.1	3.2	5.2	6.2	6.6	4.6
Effect of regulatory treatment of depreciation differences	51.7	9.7	7.9	9.4	9.8	7.5
Tax credits—net	(19.9)	(4.0)	(3.1)	(3.6)	(4.1)	(2.9)
Effect of foreign earnings at different tax rates	(1.3)	0.6	(2.1)	—	—	—
Stock sale differences	(6.8)	—	—	—	—	—
Stock sale valuation allowance	30.2	—	—	—	—	—
Other—net	(4.0)	(0.3)	0.2	(1.9)	(1.0)	—
Effective tax rate	95.0%	44.2%	43.1%	45.1%	46.3%	44.2%

Historically, the benefits of certain temporary differences have been utilized to reduce the Utility's customers rates. Accordingly, a regulatory asset has been recorded reflecting the pre-tax amount that will be recovered from customers as the temporary difference reverses. In connection with the California electric restructuring plan, the Utility is collecting the regulatory asset over four years.

During 1999, PG&E Corporation generated a capital loss carryforward of approximately $225 million, which will expire in 2005. A valuation allowance of approximately $75 million has been recorded reflecting the estimated net realizable value of this capital loss carryforward.

Note 14: Commitments

Utility

Letters of Credit and Surety Bonds:

The Utility uses $409 million in standby letters of credit and surety bonds to secure future workers' compensation liabilities.

Restructuring Trust Guarantees:

Tax-exempt restructuring trusts were established to oversee the development of the operating framework for the competitive generation market in California. (See Note 2.) The CPUC has authorized California utilities to guarantee bank loans of up to $85 million to be used by the trusts for this purpose. Under the CPUC authorization, the Utility's remaining guarantee is for up to a maximum of $38 million of the loan. The remaining bank loan will be repaid and the guarantee removed when the trust obtains proceeds from permanent financing or rate recovery.

Power Purchase Contracts:

By federal law, the Utility is required to purchase electric energy and capacity provided by independent power producers that are qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA). The CPUC established a series of QF long-term power purchase contracts and set the applicable terms, conditions, price options, and eligibility requirements.

Under these contracts, the Utility is required to make payments only when energy is supplied or when capacity commitments are met. Costs associated with these contracts are eligible for recovery by the Utility as transition costs through the collection of the nonbypassable CTC. The Utility's contracts with these power producers expire on various dates through 2028. Deliveries from these power producers account for approximately 23 percent of the Utility's 1999 electric energy requirements, and no single contract accounted for more than five percent of the Utility's energy needs.

The Utility has negotiated with several QFs for early termination of their power purchase contracts. For other contracts, the Utility has negotiated with QFs to refrain from producing energy during the remaining term of the higher fixed energy price period under their contract (a "buy-down") or to curtail energy production for shorter periods of time (a "curtailment"). At December 31, 1999, the total discounted future payments due under the renegotiated contracts that are subject to early termination, buy-down, or curtailment was $16 million, of which

$6.6 million has been recovered in rates and the Utility expects to recover the remaining $9.4 million in future rates.

The Utility also 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 whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the nonbypassable CTC. At December 31, 1999, the undiscounted future minimum payments under these contracts were $32.7 million for each of the years 2000 through 2004 and a total of $247 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately 5.8 percent of the Utility's 1999 electric energy requirements.

The amount of energy received and the total payments made under all of these power purchase contracts were:

	Year ended December 31,		
(in millions)	**1999**	**1998**	**1997**
Kilowatt-hours received	25,910	25,994	24,389
Energy payments	$837	$943	$1,157
Capacity payments	$539	$529	$ 538
Irrigation district and water agency payments	$ 60	$ 53	$ 56

Natural Gas Transportation Commitments:

The Utility has long-term gas transportation service contracts with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. The total demand and volumetric transportation charges the Utility paid under these agreements were $97 million, $113 million, and $255 million in 1999, 1998, and 1997, respectively. These amounts include payments made by the Utility to PG&E GT NW of $47 million, $49 million, and $49 million in 1999, 1998, and 1997, respectively, which are eliminated in the consolidated financial statements of PG&E Corporation.

The Utility's obligations related to capacity held pursuant to long-term contracts on various pipelines are as follows:

(in millions)	
2000	$100
2001	97
2002	78
2003	78
2004	78
Thereafter	98
Total	$529

As a result of regulatory changes, the Utility no longer procures gas for most of its industrial and larger commercial (noncore) customers, resulting in a decrease in the Utility's need for capacity on these pipelines. Despite these changes, the Utility continues to procure gas for substantially all of its residential and smaller commercial (core) customers and its noncore customers who choose bundled service. To the extent that the Utility's current capacity holdings exceed demand for gas transportation by its customers, the Utility will continue its efforts to broker such excess capacity.

National Energy Group

Power Purchase Contracts:

As a part of the acquisition of a portfolio of electric generating assets and power supply contracts from NEES (see Note 5), NEES transferred to PG&E Gen contractual rights and duties under several power purchase contracts with third-party independent power producers. At December 31, 1999, these agreements provided for an aggregate of 470 MW of capacity. Under the transfer agreement, PG&E Gen is required to pay to NEES amounts due to the third-party power producers under the power purchase contracts. PG&E Gen's payment obligations to NEES are reduced by NEES's monthly payment obligation, payable in monthly installments from September 1998 through January 2008. In certain circumstances, NEES, with the consent of PG&E Gen, will make a full or partial lump-sum accelerated payment of the monthly payment obligation to such party as PG&E Gen may direct. The approximate dollar amounts under these agreements are as follows:

(in millions)	Power Purchase Contract	Support Payments
2000	$ 233	$119
2001	228	120
2002	215	121
2003	217	112
2004	220	108
Thereafter	1,804	334
Total	$2,917	$914

Gas Supply and Transportation Agreements:

PG&E Gen is obligated to purchase and fuel suppliers are required to supply all the fuel needed at PG&E Gen's facilities. Fuel requirements include the quality and estimated quantity of fuel needed to operate each facility. The price of fuel escalates annually for the term of each contract. In addition, PG&E Gen has transportation contracts with various entities to deliver the fuel to each facility. The approximate dollar obligations under these gas supply and transportation agreements are as follows:

(in millions)	
2000	$ 103
2001	101
2002	101
2003	102
2004	11
Thereafter	848
Total	$1,266

Standard Offer Agreements:

As a part of the acquisition of a portfolio of electric generating assets and power supply contracts from NEES (see Note 5), PG&E Gen entered into agreements to supply the electric capacity and energy necessary for certain of NEES affiliates to meet their obligations to provide standard offer service. The agreements to provide standard offer service range in length from 3 to 10 years. The price per MWh is standard for all agreements. For the year ended December 31, 1999, the standard offer service price paid generators was $0.035 per Kwh for generation.

Operating Leases:

PG&E Corporation and the National Energy Group have entered into various long-term lease commitments.

PG&E Gen has an agreement to lease Lake Road under a five-year operating lease agreement which is extendible. The lease term will commence upon the completion of the construction of a gas-fired generating facility, which is anticipated to be mid-2001. The minimum obligations under this lease cannot be determined until the commencement of the lease because the minimum rent payments are based on the final cost to complete the facility. The approximate obligations below are based on the current estimated total cost of the facility.

USGenNE entered into a $479 million sale-and-leaseback transaction whereby USGenNE sold and leased back its Bear Swamp facility to a third party. The related lease is being accounted for as an operating lease. The rental expense under this lease in 1999 was $2 million.

PG&E Gen leases the Pittsfield facility from General Electric Credit Corporation. The rental expense for this facility in 1999 was $28 million.

PG&E GTT has an operating lease commitment in connection with gas storage. The term of the gas storage facility lease and related arrangements run through January 2008 and subject to certain conditions, has one or more optional renewal periods of five years each at fair market value. The rental expense for this gas storage facility in 1999 was approximately $10 million.

PG&E Corporation and our National Energy Group have leases for office space primarily located in California, Maryland, Oregon, Massachusetts, and Texas. For the year ended December 31, 1999, rent expense for these facilities amounted to $27 million.

The approximate obligations under these operating lease agreements are as follows:

(in millions)	
2000	$ 96
2001	110
2002	116
2003	109
2004	124
Thereafter	1,266
Total	$1,821

Note 15: Contingencies

Nuclear Insurance

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $15 million (property damage) and $4 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection which provides an additional $9.3 billion in coverage, which is mandated by federal legislation. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Environmental Remediation

The Utility may be required to pay for environmental remediation at sites where it has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by it for the storage or disposal of potentially hazardous materials. Under federal and California laws, it may be responsible for remediation of hazardous substances, even if it did not deposit those substances on the site.

The Utility records a liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The remediation costs also reflect (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) 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 lower end of this range.

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in estimate 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. At December 31, 1999, the Utility expects to spend $300 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The Utility had an accrued liability of $271 million and $296 million at December 31, 1999 and 1998, respectively, representing the discounted value of these costs.

Of the $271 million accrued liability discussed above, the Utility has recovered $148 million through rates, including $34 million through depreciation, and expects to recover another $95 million in future rates. Additionally, the Utility is mitigating its costs by obtaining recovery of its costs from insurance carriers and from other third parties as appropriate.

Environmental remediation at identified sites may be as much as $486 million if, among other things, other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated. The Utility estimated this upper limit of the range of costs using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or outcomes change.

Further, as discussed in "Generation Divestiture" above, the Utility will retain the pre-closing remediation liability associated with divested generation facilities.

PG&E Corporation believes the ultimate outcome of these matters will not have a material impact on its or the Utility's financial position or results of operations.

Legal Matters

Chromium Litigation:

Several civil suits are pending against the Utility in California state court. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 900 individuals.

The Utility is responding to the suits and asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations or exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

PG&E Corporation believes that the ultimate outcome of these matters will not have a material adverse impact on its or the Utility's financial position or results of operations.

Texas Franchise Fee Litigation:

In connection with PG&E Corporation's acquisition of Valero Energy Corporation, now known as PG&E Gas Transmission Texas (PG&E GTT), PG&E GTT succeeded to the litigation described below.

PG&E GTT and various of its affiliates are defendants in at least two class action suits and five separate suits filed by various Texas cities. Generally, these cities allege, among other things, that (1) owners or operators of pipelines occupied city property and conducted pipeline operations without the cities' consent and without compensating the cities, and (2) the gas marketers failed to pay the cities for accessing and utilizing the pipelines located in the cities to flow gas under city streets. Plaintiffs also allege various other claims against the defendants for failure to secure the cities' consent. Damages are not quantified.

In 1998, a jury trial was held in the separate suit brought by the City of Edinburg (the City). This suit involved, among other things, a particular franchise agreement entered into by a former subsidiary of PG&E GTT (now owned by Southern Union Gas Company (SU)) and the City and certain conduct of the defendants. On December 1, 1998, based on the jury verdict, the court entered a judgment in the City's favor, and awarded damages of $5.3 million, and attorneys' fees of up to $3.5 million plus interest. The court found that various PG&E GTT and SU defendants were jointly and severally liable for $3.3 million of the damages and all the attorneys' fees. Certain PG&E GTT subsidiaries were found solely liable for $1.4 million of the damages. The court did not clearly indicate the extent to which the PG&E GTT defendants could be found liable for the remaining damages. The PG&E GTT defendants are in the process of appealing the judgment.

In connection with the certification of a class in one of the class actions, the court ordered notice to be sent to all potential class members and setting an opt-out deadline of December 31, 1997. Notices were mailed to approximately 159 Texas cities. Fewer than 20 cities opted out by the deadline. In November 1999, the court signed an order dismissing from the class 42 cities because it determined there was no pipeline presence and no past or present sales activity, leaving 106 cities in the class. The parties in this class action are negotiating the terms of a settlement agreement. The settlement proposal contemplates, among other things, that the PG&E Corporation defendants would pay $12.2 million to the class cities, inclusive of attorney fees, reduced by amounts attributable to opt-out cities. The defendants retain the right to reject the settlement if the settlement proposal is not approved by certain key cities and by 80% of the plaintiff class. Although a significant number of the 106 cities in the plaintiff class already have either approved the settlement or adopted resolutions to pass the ordinance, certain key cities have not yet approved the settlement. The settlement is also subject to court approval. On January 27, 2000, the court approved the settlement proposal and established a 14-day period whether to accept the negotiated settlement terms or opt out of the settlement. The Court also stated that if Corpus Christi does not accept the settlement proposal, it will be placed in a sub-class, whose claims will not be finalized as part of the settlement approval. Corpus Christi has the right to opt out of this subclass.

PG&E Corporation believes that the ultimate outcome of these matters will not have a material adverse impact on its financial position or its results of operations. As discussed above in Note 5, in January 2000, PG&E Corporation's National Energy Group signed a definitive agreement to sell the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. The buyer will assume all liabilities associated with the cases described above.

Recorded Liability for Legal Matters:

In accordance with SFAS No. 5, PG&E Corporation makes a provision for a liability when both it is 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, rulings, advice of legal counsel, and other information and events pertaining to a particular case. In the fourth quarter of 1999, PG&E Corporation reduced the amount of the recorded liability for legal matters associated with a court approved settlement proposal and other settlement discussions of certain matters described above. Approximately $55 million of the adjustments, arising from a pre-acquisition contingency related to a purchased business, are reflected in "Other income, net" in PG&E Corporation's Statement of Consolidated Income. The following table reflects the current year's activity to the recorded liability for legal matters:

(in millions)	PG&E Corporation	Utility
Beginning Balance, January 1, 1999	$175	$ 52
Provisions for liabilities	16	14
Payments	(41)	(29)
Adjustments	(44)	13
Ending Balance, December 31, 1999:	$106	$ 50

Note 16: General Rate Case

In December 1997, the Utility filed its 1999 application with the CPUC During the GRC process, the CPUC examines the Utility's costs to determine the amount the Utility may charge customers for base revenues (non-fuel related costs). The Utility requested distribution revenue increases to maintain and improve natural gas and electric distribution reliability, safety, and customer service. The requested revenues, as updated, included an increase of $445 million in electric base revenues and an increase of $377 million in natural gas base revenues over the 1998 authorized revenues.

The Utility received a final decision on its 1999 GRC application on February 17, 2000. This final decision increased electric distribution revenues by $163 million and gas distribution revenues by $93 million, as compared to revenues authorized for 1998. This revenue increase is retroactive to January 1, 1999. The impact of these increases resulted in an increase in earnings of $153 million, or $0.42 per share, and was reflected in the fourth quarter of 1999.

Note 17: Segment Information

PG&E Corporation has identified four reportable operating segments. The Utility is one reportable operating segment and the other three are part of PG&E Corporation's National Energy Group. These four reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Utility:

PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company, provides natural gas and electric service to one of every 20 Americans.

National Energy Group:

The National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC (formerly U.S. Generating Company, LLC) and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and in Texas, through various subsidiaries of PG&E Corporation (collectively, PG&E Gas Transmission or PG&E GT); and purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the other National Energy Group non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading—Gas Corporation, PG&E Energy Trading—Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET). In the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's Texas natural gas and natural gas liquids business. Also in the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's retail energy services, conducted through PG&E ES. PG&E ES had total assets of $197 million, $202 million, and $60 million, as of December 31, 1999, 1998, and 1997, respectively.

Segment information for the years 1999, 1998, and 1997 was as follows:

	Utility	National Energy Group					
(in millions)		PG&E Gen	PG&E GT NW	PG&E GT Texas	PG&E ET	Eliminations & Other	Total
1999							
Operating revenues	$ 9,084	$1,116	$ 172	$1,034	$9,404	$ 10	$20,820
Intersegment revenues[1]	144	6	52	114	1,117	(1,433)	—
Total operating revenues	9,228	1,122	224	1,148	10,521	(1,423)	20,820
Depreciation, amortization and decommissioning	1,564	89	41	75	9	2	1,780
Interest expense[2]	(593)	(63)	(41)	(59)	(12)	(4)	(772)
Other income (expense)	11	61	21	53	3	6	155
Income taxes[3]	648	16	32	(407)	(36)	(5)	248
Income from continuing operations	763	97	68	(897)	(34)	16	13
Capital expenditures	1,181	323	30	19	14	—	1,567
Total assets at year-end[4]	$21,470	$3,852	$1,160	$1,217	$1,876	$ (57)	$29,518
1998							
Operating revenues	$ 8,919	$ 645	$ 185	$1,640	$8,183	$ 5	$19,577
Intersegment revenues[1]	5	4	52	301	326	(688)	—
Total operating revenues	8,924	649	237	1,941	8,509	(683)	19,577
Depreciation, amortization and decommissioning	1,438	52	39	65	5	3	1,602
Interest expense[2]	(621)	(43)	(43)	(77)	(7)	10	(781)
Other income (expense)	76	18	3	13	5	(50)	65
Income taxes[3]	629	28	31	(47)	(17)	(13)	611
Income (loss) from continuing operations	702	106	65	(71)	(6)	(25)	771
Capital expenditures	1,396	98	49	39	12	1	1,595
Total assets at year-end[4]	$22,950	$3,844	$1,169	$2,655	$2,555	$ (141)	$33,032
1997							
Operating revenues	$ 9,495	$ 148	$ 186	$ 800	$4,613	$ 13	$15,255
Intersegment revenues[1]	—	—	47	204	195	(446)	—
Total operating revenues	9,495	148	233	1,004	4,808	(433)	15,255
Depreciation, amortization and decommissioning	1,748	19	38	33	3	10	1,851
Interest expense[2]	(570)	(5)	(41)	(26)	(2)	(20)	(664)
Other income (expense)	94	(25)	1	13	3	126	212
Income taxes[3]	609	(17)	26	(8)	(12)	(33)	565
Income (loss) from continuing operations	735	(41)	40	(24)	(19)	54	745
Capital expenditures	1,529	23	34	45	5	50	1,686
Total assets at year-end[4]	$25,147	$ 989	$1,208	$2,800	$1,452	$ (541)	$31,055

(1) Intersegment electric and gas revenues are recorded at market prices, which for the Utility and PG&E GT NW are tariffed rates prescribed by the CPUC and FERC, respectively.

(2) Net interest expense incurred by PG&E Corporation is allocated to the segments using specific identification.

(3) Income tax expense for the Utility is computed on a stand-alone basis. The balance of the consolidated income tax provision is allocated among the National Energy Group.

(4) Assets of PG&E Corporation are included in "Eliminations & Other" column exclusive of investment in its subsidiaries.

(5) Income from equity-method investees for 1999, 1998, and 1997 was $61 million, $113 million, and $41 million, respectively, for PG&E Gen, and none, $3 million, and $2 million, respectively, for PG&E GTT.

Note 18: Fair Value of Financial Instruments

PG&E Corporation estimates fair value of its financial instruments based on quoted market prices, where available. Fair value of the Utility's rate reduction bonds, and Utility obligated manditorily redeemable preferred securities of trust holding solely Utility subordinated debentures are all determined based on quoted market prices. Fair value of the Utility's preferred stock with mandatory provisions is based on indicative market prices. Where quoted or indicative market prices are not available, the estimated fair value is determined using other valuation techniques (for example, the present value of future cash flows). Most of PG&E Corporation's and the Utility's debt is determined using quoted market prices, but the fair value of a small portion of Utility debt is determined using the present value of future cash flows. The carrying value of PG&E Corporation's short-term borrowings approximates fair value.

At December 31, 1999 and 1998, PG&E Corporation's carrying amount and ending fair value of its financial instruments are:

	1999		1998	
(in millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
PG&E Corporation:				
Current price risk management assets (see Note 3)	$ 607	$ 607	$1,416	$1,416
Noncurrent price risk management assets (see Note 3)	372	372	334	334
Current price risk management liabilities (see Note 3)	575	575	1,412	1,412
Noncurrent price risk management liabilities (see Note 3)	247	247	281	281
Total long-term debt[1] (see Note 8)	7,265	7,095	7,760	8,079
Utility:				
Nuclear decommissioning funds noncurrent asset (see Note 11)	1,264	1,264	1,172	1,172
Total long-term debt[1] (see Note 8)	5,342	5,217	5,704	6,008
Rate reduction bonds[2] (see Note 9)	2,321	2,265	2,611	2,676
Preferred stock with mandatory redemption provisions (see Note 7)	137	140	137	143
Utility obligated mandatorily redeemable preferred securities of trust holding solely Utility subordinated debentures (see Note 7)	300	267	300	303

(1) Total long-term debt includes current portion of long-term debt.

(2) Rate reduction bonds include current portion of rate reduction bonds.

Quarterly Consolidated Financial Data (Unaudited)

Quarter ended (in millions, except per share amounts)	December 31	September 30	June 30	March 31
1999				
PG&E Corporation				
Operating revenues	$4,795	$6,217	$4,682	$5,126
Operating income (loss)(1)(2)(3)	(579)	516	480	461
Income (loss) from continuing operations	(547)	197	196	167
Net income (loss)(1)(2)(3)	(611)	185	182	171
Earnings (loss) per common share from continuing operations, basic	(1.49)	0.54	0.53	0.45
Earnings (loss) per common share from continuing operations, diluted	(1.49)	0.54	0.50	0.39
Dividends declared per common share	0.30	0.30	0.30	0.30
Common stock price per share				
High	26.69	33.25	34.00	33.69
Low	20.25	25.00	30.56	29.50
Utility				
Operating revenues	$2,323	$2,587	$2,233	$2,085
Operating income(3)	633	486	452	422
Net income(3)	272	185	178	153
Income available for common stock	265	179	172	147
1998				
PG&E Corporation				
Operating revenues	$5,364	$5,208	$4,695	$4,310
Operating income(1)	485	554	579	480
Income from continuing operations	208	225	188	150
Net income(1)	196	210	174	139
Earnings per common share from continuing operations, basic and diluted	0.54	0.59	0.49	0.39
Dividends declared per common share	0.30	0.30	0.30	0.30
Common stock price per share				
High	35.06	33.44	33.19	33.56
Low	30.38	29.88	30.06	29.06
Utility				
Operating revenues	$2,218	$2,563	$2,117	$2,026
Operating income	446	512	494	424
Net income	176	205	193	155
Income available for common stock	169	199	186	148

(1) In the fourth quarter 1999, the National Energy Group adopted a plan to dispose of the PG&E ES segment. This planned transaction has been accounted for as a discontinued operation. Results of operations of PG&E ES have been excluded from continuing operations for all periods presented. The operating loss and net loss of PG&E ES for the quarters ending March 31, June 30, and September 30, 1999, were $15 million and $8 million, $23 million and $14 million, and $20 million and $12 million, respectively. The operating loss and net loss for PG&E ES for the quarters ending March 31, June 30, and September 30, 1998, were $17 million and $11 million, $22 million and $14 million, and $27 million and $15 million, respectively.

(2) Amounts have been restated to reflect the change in accounting for major maintenance and overhauls at the National Energy Group (see Note 1 of the Notes to Consolidated Financial Statements), and reclassification of PG&E ES operating results to discontinued operations (see above). The accounting change resulted in a cumulative effect being recorded as of January 1, 1999, of $12 million ($0.03 per share), net of income taxes of $8 million. Operating income previously reported for 1999 was $442 million, $454 million, and $492 million for each of the first three quarters, respectively. Net income previously reported for 1999 was $156 million ($0.42 per share), $180 million ($0.49 per share), and $183 million ($0.50 per share) for the same periods.

(3) In the fourth quarter 1999, the Utility recorded the effects of the outcome of the GRC. This resulted in an increase of $256 million in operating income and an increase of $153 million in net income. Additionally, the National Energy Group recorded an after-tax charge of $890 million reflecting PG&E GTT's assets at their fair market value. (See Notes 5 and 16 of the Notes to Consolidated Financial Statements.)

INDEPENDENT AUDITORS' REPORT

To the Board 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 and of Pacific Gas and Electric Company and subsidiaries as of December 31, 1999, and the related statements of consolidated income, cash flows, and common stock equity of PG&E Corporation and the related statements of consolidated income, cash flows, and stockholders' equity of Pacific Gas and Electric Company for the year then ended. These financial statements are the responsibility of management of PG&E Corporation and of Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements for the years ended December 31, 1998 and 1997 were audited by other auditors whose report, dated February 8, 1999, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with generally accepted auditing standards. 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 1999 financial statements present fairly, in all material respects, the consolidated financial position of PG&E Corporation and Pacific Gas and Electric Company as of December 31, 1999, and the results of their consolidated operations and cash flows for the year then ended in conformity with generally accepted accounting principles.

As discussed in Note 1 of the Notes to Consolidated Financial Statements, in 1999 PG&E Corporation changed its method of accounting for major maintenance and overhauls cost.

DELOITTE & TOUCHE LLP
San Francisco, California
March 3, 2000

RESPONSIBILITY FOR CONSOLIDATED FINANCIAL STATEMENTS

At both PG&E Corporation and Pacific Gas and Electric Company (the Utility) management is responsible for the integrity of the accompanying consolidated financial statements. These statements have been prepared in accordance with generally accepted accounting principles. Management considers materiality and uses its best judgment to ensure that such statements reflect fairly the financial position, results of operations, and cash flows of PG&E Corporation and the Utility.

PG&E Corporation and the Utility maintain systems of internal controls supported by formal policies and procedures which are communicated throughout PG&E Corporation and the Utility. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and that necessary records are produced for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on recognition that the costs of such systems should not exceed the benefits to be derived. PG&E Corporation and the Utility believe that their systems of internal control provide this appropriate balance. PG&E Corporation management also maintains a staff of internal auditors who evaluate the adequacy of, and assess the adherence to, these controls, policies, and procedures for all of PG&E Corporation, including the Utility.

Both PG&E Corporation's and the Utility's 1999 consolidated financial statements have been audited by Deloitte & Touche LLP, PG&E Corporation's independent auditors. The audit includes consideration of internal accounting controls and performance of tests necessary to support an opinion. The auditors' report contains an independent informed judgment as to the fairness, in all material respects, of reported results of operations and financial position.

The Audit Committee of the Board of Directors for PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche, jointly and separately, to review internal accounting controls and auditing and financial reporting matters. The internal auditors and Deloitte & Touche LLP have free access to the Audit Committee, which consists of five outside directors. The Audit Committee has reviewed the financial data contained in this report.

PG&E Corporation and the Utility are committed to full compliance with all laws and regulations and to conducting business in accordance with high standards of ethical conduct. Management has taken the steps necessary to ensure that all employees and other agents understand and support this commitment. Guidance for corporate compliance and ethics is provided by an officers' Ethics Committee and by a Legal Compliance and Business Ethics organization. PG&E Corporation and the Utility believe that these efforts provide reasonable assurance that each of their operations is conducted in conformity with applicable laws and with their commitment to ethical conduct.

Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company(1)

Richard A. Clarke
Chairman of the Board, Retired, Pacific Gas and Electric Company

Harry M. Conger
Chairman of the Board and Chief Executive Officer, Emeritus, Homestake Mining Company

David A. Coulter
Partner, Beacon Group, L.P.

C. Lee Cox
Vice Chairman, Retired, AirTouch Communications, Inc. and President and Chief Executive Officer, Retired, AirTouch Cellular

William S. Davila
President Emeritus, The Vons Companies, Inc. (retail grocery)

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation and Chairman of the Board, Pacific Gas and Electric Company

David M. Lawrence, MD
Chairman and Chief Executive Officer, Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals

Richard B. Madden(2)
Chairman of the Board and Chief Executive Officer, Retired, Potlatch Corporation (diversified forest products)

Mary S. Metz
President, S. H. Cowell Foundation

Rebecca Q. Morgan(2)
President and Chief Executive Officer, Retired, Joint Venture: Silicon Valley Network (nonprofit collaborative addressing critical issues facing Silicon Valley)

Carl E. Reichardt
Chairman of the Board and Chief Executive Officer, Retired, Wells Fargo & Company and Wells Fargo Bank, N.A.

John C. Sawhill
President and Chief Executive Officer, The Nature Conservancy (international environmental organization)

Gordon R. Smith(1)
President and Chief Executive Officer, Pacific Gas and Electric Company

Barry Lawson Williams
President, Williams Pacific Ventures, Inc. (business consulting and mediation)

(1) The composition of the Boards of Directors is the same, except that Gordon R. Smith is a director of the Pacific Gas and Electric Company Board of Directors only.

(2) Retired as a director of PG&E Corporation and Pacific Gas and Electric Company on February 16, 2000.

Permanent Committees of PG&E Corporation and Pacific Gas and Electric Company[1]

Executive Committees

Within limits, may exercise powers and perform duties of the Boards.

Robert D. Glynn, Jr., Chair
Harry M. Conger
Mary S. Metz
Carl E. Reichardt
Gordon R. Smith[1]
Barry Lawson Williams

Audit Committee

Reviews financial statements and internal audit and control procedures with independent public accountants.

Harry M. Conger, Chair
C. Lee Cox
William S. Davila
Mary S. Metz
Barry Lawson Williams

Finance Committee

Reviews long-term financial and capital investment policies and objectives, and actions required to achieve those objectives.

Barry Lawson Williams, Chair
Richard A. Clarke
David A. Coulter
Carl E. Reichardt
John C. Sawhill

Nominating and Compensation Committee

Recommends candidates for nomination as directors, recommends compensation and employee benefit policies and practices, and reviews planning for executive development and succession.

Carl E. Reichardt, Chair
David A. Coulter
C. Lee Cox
David M. Lawrence, MD
John C. Sawhill

Public Policy Committee

Reviews public policy issues which could significantly affect customers, shareholders, employees, or the communities served, and recommends plans and programs to address such issues.

Mary S. Metz, Chair
Richard A. Clarke
William S. Davila
John C. Sawhill

(1) The committee membership shown is effective February 16, 2000. Except for the Executive Committee, all committees listed above are committees of the PG&E Corporation Board of Directors. The Executive Committees of the PG&E Corporation and Pacific Gas and Electric Company Boards have the same members, except that Gordon R. Smith is a member of the Pacific Gas and Electric Company Executive Committee only.

Officers

PG&E Corporation

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer, and President

Thomas G. Boren
Executive Vice President

Peter A. Darbee
Senior Vice President, Chief Financial Officer, and Treasurer

Tony F. DiStefano
Senior Vice President

Scott W. Gebhardt
Senior Vice President

Thomas W. High
Senior Vice President, Administration and External Relations

P. Chrisman Iribe
Senior Vice President

Thomas B. King
Senior Vice President

L. E. Maddox
Senior Vice President

Gordon R. Smith
Senior Vice President

G. Brent Stanley
Senior Vice President, Human Resources

Bruce R. Worthington
Senior Vice President and General Counsel

Leslie H. Everett
Vice President and Corporate Secretary

Christopher P. Johns
Vice President and Controller

Steven L. Kline
Vice President, Federal Governmental and Regulatory Relations

Jackalyne Pfannenstiel
Vice President, Corporate Initiatives

Greg S. Pruett
Vice President, Corporate Communications

Daniel D. Richard, Jr.
Vice President, Governmental Relations

M. Richard Smith
Vice President, Corporate Development

National Energy Group

Thomas G. Boren
President and Chief Executive Officer

Scott W. Gebhardt
President and Chief Executive Officer, PG&E Energy Services

P. Chrisman Iribe
President and Chief Operating Officer, PG&E Generating

Thomas B. King
President and Chief Operating Officer, PG&E Gas Transmission

L. E. Maddox
President and Chief Executive Officer, PG&E Energy Trading

Pacific Gas and Electric Company

Gordon R. Smith
President and Chief Executive Officer

Kent M. Harvey
Senior Vice President, Chief Financial Officer, Controller, and Treasurer

Roger J. Peters
Senior Vice President and General Counsel

James K. Randolph
Senior Vice President and General Manager, Transmission, Distribution, and Customer Service Business Unit

Daniel D. Richard, Jr.
Senior Vice President, Public Affairs

Gregory M. Rueger
Senior Vice President and General Manager, Nuclear Power Generation Business Unit

Russell M. Jackson
Vice President, Human Resources

Shareholder Information

For financial and other information about PG&E Corporation and Pacific Gas and Electric Company, please visit our websites, www.pgecorp.com and www.pge.com.

If you have questions about your PG&E Corporation common stock account or Pacific Gas and Electric Company preferred stock account, or need copies of PG&E Corporation's or Pacific Gas and Electric Company's publications, please write or call ChaseMellon Shareholder Services:

ChaseMellon Shareholder Services
P.O. Box 3310 (Securities Transfer)
P.O. Box 3315 (General Correspondence)
P.O. Box 3316 (Change of Address)
P.O. Box 3317 (Lost Certificate Replacement)
P.O. Box 3338 (Dividend Reinvestment)
South Hackensack, NJ 07606

Toll-free Telephone Services: 1.800.719.9056
Website: www.chasemellon.com

If you have general questions about PG&E Corporation or Pacific Gas and Electric Company, please write or call the Vice President and Corporate Secretary's Office:

Vice President and Corporate Secretary
Leslie H. Everett
PG&E Corporation
P.O. Box 193722
San Francisco, CA 94119-3722
415.267.7070
Fax 415.267.7268

Securities analysts, portfolio managers, or other representatives of the investment community should write or call the Investor Relations Office:

Manager of Investor Relations
Jamie Fenton
PG&E Corporation
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105
415.267.7080
Fax 415.267.7265

PG&E Corporation
General Information
415.267.7000

Pacific Gas and Electric Company
General Information
415.973.7000

Stock Exchange Listings

PG&E Corporation's common stock is traded on the New York, Pacific, and Swiss stock exchanges. The official New York Stock Exchange symbol is "PCG" but PG&E Corporation common stock is listed in daily newspapers under "PG&E" or "PG&E Cp."[(1)]

Pacific Gas and Electric Company has 11 issues of preferred stock and one preferred security, all of which are listed on the American and Pacific stock exchanges.

Issue	Newspaper Symbol[(1)]
First Preferred, Cumulative, Par Value $25 Per Share	
Redeemable:	
7.04%	PacGE pfU
6.57%	PacGE pfY
6.30%	PacGE pfZ
5.00%	PacGE pfD
5.00% Series A	PacGE pfE
4.80%	PacGE pfG
4.50%	PacGE pfH
4.36%	PacGE pfI
Non-Redeemable:	
6.00%	PacGE pfA
5.50%	PacGE pfB
5.00%	PacGE pfC
Cumulative Quarterly Income Preferred Securities:	
7.90% Series A	PG&E Cap pfA

2000 Dividend Payment Dates

PG&E Corporation Common Stock	Pacific Gas and Electric Company Preferred Stock
January 15	February 15
April 15	May 15
July 15	August 15
October 15	November 15

Stock Held in Brokerage Accounts ("Street Name")

When you purchase your stock and it is held for you by your broker, the shares are listed with ChaseMellon Shareholder Services in the broker's name, or "street name." ChaseMellon Shareholder Services does not know the identity of the individual shareholders who hold their shares in this manner—they simply know that a broker holds a number of shares which may be held for any number of investors. If you hold your stock in a street name account, you receive all dividend payments, tax forms, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

PG&E Corporation Dividend Reinvestment Plan

If you hold PG&E Corporation or Pacific Gas and Electric Company stock in your own name, rather than through a broker, you may automatically reinvest dividend payments from common and/or preferred stock in shares of PG&E Corporation common stock through the Dividend Reinvestment Plan (the "Plan"). You may obtain a Plan prospectus and enroll by contacting ChaseMellon Shareholder Services. If your certificates are held by a broker (in "street name"), you are not eligible to participate in the Plan.

(1) Local newspaper symbols may vary.

Direct Deposit of Dividends
If you hold stock in your own name, rather than through a broker, you may have your common and/or preferred dividends transmitted to your bank electronically. You may obtain a direct deposit authorization form by contacting ChaseMellon Shareholder Services.

Replacement of Dividend Checks
If you hold stock in your own name and do not receive your dividend check within seven business days after the payment date, or if a check is lost or destroyed, you should notify ChaseMellon Shareholder Services so that payment can be stopped on the check and a replacement mailed.

Lost or Stolen Stock Certificates
If you hold stock in your own name and your stock certificate has been lost, stolen, or in some way destroyed, you should notify ChaseMellon Shareholder Services immediately.

PG&E Corporation
Pacific Gas and Electric Company
Annual Meetings of Shareholders

Date: April 19, 2000
Time: 10:00 a.m.

Location: Four Seasons Hotel—Boston
200 Boylston Street
Boston, Massachusetts

A joint notice of the annual meetings, joint proxy statement, and proxy form are being mailed with this annual report on or about March 13, 2000, to all shareholders of record as of February 22, 2000.

10-K Report
If you would like a copy of the 1999 Form 10-K Report to the Securities and Exchange Commission, please contact the Office of the Vice President and Corporate Secretary, or visit our websites, www.pgecorp.com and www.pge.com.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 1999

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 of Incorporation	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640

Pacific Gas and Electric Company	PG&E Corporation
77 Beale Street P.O. Box 770000 San Francisco, California (Address of principal executive offices)	One Market, Spear Tower Suite 2400 San Francisco, California (Address of principal executive offices)
94177 (Zip Code)	94105 (Zip Code)
(415) 973-7000 (Registrant's telephone number, including area code)	(415) 267-7000 (Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation Common Stock, no par value	New York Stock Exchange and Pacific Exchange
Pacific Gas and Electric Company First Preferred Stock, cumulative, par value $25 per share: Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36% Mandatorily Redeemable: 6.57%, 6.30% Nonredeemable: 6%, 5.50%, 5%	American Stock Exchange and Pacific Exchange
7.90% Cumulative Quarterly Income Preferred	American Stock Exchange and

Securities, Series A (liquidation preference $25), issued by PG&E Capital I and guaranteed by Pacific Gas and Electric Company	Pacific Exchange

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

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.

Yes [X] 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. [_]

Aggregate market value of the voting stock held by non-affiliates of the registrant as of February 22, 2000:

PG&E Corporation Common Stock	$8,095 million
Pacific Gas and Electric Company First Preferred Stock	$331 million

Common Stock outstanding as of February 22, 2000:

PG&E Corporation:	384,825,799
Pacific Gas and Electric Company:	Wholly owned by PG&E Corporation

The market values of certain series of First Preferred Stock, for which market prices as of a date within 60 days prior to the date of filing were not available, were derived by dividing the annual dividend rate of each such series of stock by the average yield of all of Pacific Gas and Electric Company's Preferred Stock outstanding for which market prices were available.

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.

(1) Designated portions of the combined Annual Report to Shareholders for the year ended December 31, 1999.....	Part I (Item 1), Part II (Items 5, 6, 7, 7A, and 8) Part IV (Item 14)
(2) Designated portions of the Joint Proxy Statement relating to the 2000 Annual Meetings of Shareholders..	Part III (Items 10, 11, 12, and 13)

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GLOSSARY OF TERMS

AB 1890	Assembly Bill 1890, the California electric industry restructuring legislation
AEAP	Annual Earnings Assessment Proceeding
ATCP	Annual Transition Cost Proceeding
BCAP	Biennial Cost Allocation Proceeding
bcf	billion cubic feet
BRPU	Biennial Resource Plan Update
BTA	best technology available
Btu	British thermal unit
CARE	California Alternate Rates for Energy
CCAA	California Clean Air Act
CEC	California Energy Commission
CEMA	Catastrophic Event Memorandum Account
Central Coast Board	Central Coast Regional Water Quality Control Board
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
core customers	residential and smaller commercial gas customers
core subscription customers	noncore customers who choose bundled service
CPIM	core procurement incentive mechanism
CPUC	California Public Utilities Commission
CTC	competition transition charge
Diablo Canyon	Diablo Canyon Nuclear Power Plant
DOE	United States Department of Energy
DSM	demand side management
EDRA	Electric Deferred Refund Account
El Paso	El Paso Natural Gas Company
EMF	electric and magnetic fields
EPA	United States Environmental Protection Agency
ERCA	Electric Restructuring Costs Account
FERC	Federal Energy Regulatory Commission
Gas Accord	Gas Accord Settlement
Geysers	The Geysers Power Plant
GRC	General Rate Case
Holding Company Act	Public Utility Holding Company Act of 1935
Humboldt	Humboldt Bay Power Plant
HWRC	hazardous waste remediation costs
ICIP	Incremental Cost Incentive Price
IPP	Independent power producer
ISO	Independent System Operator
kV	kilovolts
kVa	kilovolt-amperes
kW	kilowatts
kWh	kilowatt-hour
LEV	low emission vehicle
Mcf	thousand cubic feet
MDt	thousand decatherms
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MW	megawatts
MWh	megawatt-hour
NEES	New England Electric System
NEIL	Nuclear Electric Insurance Limited

NGL	natural gas liquids
noncore customers	industrial and larger commercial gas customers
NOx	oxides of nitrogen
NRC	Nuclear Regulatory Commission
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
ORA	Office of Ratepayer Advocates, a division of the California Public Utilities Commission
PBR	performance-based ratemaking
PG&E Expansion	the Pacific Gas and Electric Company portion of the Pipeline Expansion
PG&E ET	PG&E Corporation's energy commodities activities, PG&E Energy Trading or PG&E ET
PG&E ES	PG&E Corporation's energy services operations, PG&E Energy Services or PG&E ES
PG&E Gen	PG&E Generating Company, LLC and its affiliates
PG&E GT	PG&E Corporation's gas transmission operations, PG&E Gas Transmission or PG&E GT
PG&E GT-Northwest	PG&E Gas Transmission, Northwest Corporation formerly known as Pacific Gas Transmission Company
PG&E GT NW Expansion	PG&E Gas Transmission, Northwest Corporation's portion of the Pipeline Expansion
PG&E GTT	PG&E Gas Transmission, Texas Corporation
PG&E OSC	PG&E Operating Services Company
Pipeline Expansion	PG&E GT NW/PG&E Pipeline Expansion
PPPs	public purpose programs
PRP	potentially responsible party
PURPA	Public Utility Regulatory Policies Act of 1978
PX	California Power Exchange
QF	qualifying facility
RAP	Revenue Adjustment Proceeding
RRC	The Railroad Commission of Texas
SEC	Securities and Exchange Commission
SOS	Standard Offer Service
Teco	Teco Pipeline Company
TCBA	Transition Cost Balancing Account
TRA	Transition Revenue Account
Transwestern	Transwestern Pipeline Company
USGenNE	US Gen New England, Inc.
Utility	Pacific Gas and Electric Company and it subsidiaries
Valero	Valero Energy Corporation

PART I

ITEM 1. Business.

GENERAL

Corporate Structure and Business

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. Effective January 1, 1997, Pacific Gas and Electric Company (sometimes referred to herein as the "Utility") and its subsidiaries became subsidiaries of PG&E Corporation, which was incorporated in 1995. Pacific Gas and Electric Company, incorporated in California in 1905, is an operating public utility engaged principally in the business of providing electricity and natural gas distribution and transmission services throughout most of Northern and Central California. The Utility is primarily regulated by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). In the holding company reorganization, Pacific Gas and Electric Company's outstanding common stock was converted on a share-for-share basis into PG&E Corporation common stock. Pacific Gas and Electric Company's debt securities and preferred stock were unaffected and remain securities of Pacific Gas and Electric Company.

The consolidated financial statements of PG&E Corporation incorporated herein include the accounts of PG&E Corporation and its wholly owned and controlled subsidiaries (collectively, PG&E Corporation). The consolidated financial statements of Pacific Gas and Electric Company incorporated herein include the accounts of Pacific Gas and Electric Company and its wholly owned and controlled subsidiaries.

The principal executive offices of PG&E Corporation are located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive offices of Pacific Gas and Electric Company are located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000.

In addition to the regulated utility business of Pacific Gas and Electric Company, PG&E Corporation's National Energy Group provides energy products and services throughout North America. The National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC (formerly U.S. Generating Company, LLC) and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and Texas, through various subsidiaries of PG&E Corporation (collectively, PG&E Gas Transmission or PG&E GT); purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the National Energy Group's non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading--Gas Corporation, PG&E Energy Trading--Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET); and provide competitively priced electricity, natural gas, and related services to industrial, commercial, and institutional customers through PG&E Energy Services Corporation (PG&E Energy Services or PG&E ES). In the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E Corporation's Texas natural gas and natural gas liquids business. Also in the fourth quarter of 1999, PG&E Corporation's Board of Directors approved a plan for the divestiture of PG&E

Corporation's retail energy services. See "National Energy Group--Gas Transmission Operations" and "National Energy Group--Energy Services" below.

As of December 31, 1999, PG&E Corporation had $29.7 billion in assets. PG&E Corporation generated $20.8 billion in operating revenues for 1999. As of December 31, 1999, PG&E Corporation and its subsidiaries and affiliates had 22,433 employees. As of December 31, 1999, Pacific Gas and Electric Company had $21.4 billion in assets. The Utility generated $9.2 billion in operating revenues for 1999. As of December 31, 1999, the Utility had 18,935 employees.

The gas and electric utility operations of Pacific Gas and Electric Company represent the largest component of PG&E Corporation's business, contributing 44% of PG&E Corporation's total revenues in 1999.

PG&E Corporation has identified four reportable operating segments. The Utility is one reportable operating segment and the other three are part of PG&E Corporation's National Energy Group (PG&E Gen, PG&E GT, and PG&E ET). Financial information about each reportable operating segment is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders and in Note 17 of the "Notes to Consolidated Financial Statements" beginning on page 63 of PG&E Corporation's 1999 Annual Report to Shareholders, portions of which are filed as Exhibit 13 to this report.

The following report includes forward-looking statements about the future that involve a number of risks and uncertainties. These statements are based on assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements. Although 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 include: the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States; operational changes related to industry restructuring, including changes to the Utility's business processes and systems; the method and timing of disposition and valuation of the Utility's hydroelectric generation assets; the timing of the completion of the Utility's transition cost recovery and the consequent end of the current electric rate freeze in California; any changes in the amount the Utility is allowed to collect (recover) from its customers for certain costs which prove to be uneconomic under the new competitive market (called transition costs); future operating performance at the Utility's Diablo Canyon Nuclear Power Plant (Diablo Canyon); the method adopted by the CPUC for sharing the net benefits of operating Diablo Canyon with ratepayers and the timing of the implementation of the adopted method; the extent of anticipated growth of transmission and distribution services in the Utility's service territory; future market prices for electricity; future fuel prices; the success of management's strategies to maximize shareholder value in PG&E Corporation's National Energy Group which may include acquisitions or dispositions of assets or internal restructuring; the extent to which current or planned generation development projects are completed and the pace and cost of such completion; generating capacity expansion and retirements by others; the successful integration and performance of acquired assets; the outcome of the Utility's various regulatory proceedings, including the the proposal to auction the Utility's hydroelectric generation assets, the electric transmission rate case applications, and post-transition period ratemaking proceedings; fluctuations in commodity gas, natural gas liquid, and electricity prices and the ability to successfully manage such price fluctuations; and the pace and extent of competition in the California generation market and its impact on the Utility's costs and resulting collection of transition costs. As the ultimate impact of these and other factors is uncertain, these and other factors may cause future results to differ materially from results or outcomes currently expected or sought by PG&E Corporation.

Competition and the Changing Regulatory Environment

The electric and gas industries are continuing to undergo significant change. Under traditional regulation, utilities were provided the opportunity to earn a fair return on their invested capital in exchange for a commitment to serve all customers within a designated service territory. 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 1998, California became one of the first states in the country to implement electric industry restructuring and establish a competitive market framework for electric generation. Today, most Californians may continue to purchase their electricity from investor-owned utilities (such as Pacific Gas and Electric Company) or they may choose to purchase electricity from alternative generation providers (such as unregulated power generators and unregulated retail electricity suppliers such as marketers, brokers, and aggregators). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as Pacific Gas and Electric Company, continue to be the generation providers. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including those customers who choose an alternative generation provider. The framework for electric industry restructuring was established in Assembly

Bill 1890 (AB 1890) passed by the California Legislature and signed by the Governor in 1996. For information about California electric industry restructuring, see "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring" below.

Although the initial stages of restructuring have focussed on competition among suppliers of generation, the CPUC also is studying the effect of distributed generation (where the electric energy source is located in close proximity to electric demand) in the California generation market and possible changes in the electric distribution function of traditional utilities. See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring--Distributed Generation and Electric Distribution Competition" below.

Restructuring of the natural gas industry on both the national and the state level has given choices to California utility customers to meet their gas supply needs. In August 1997, the CPUC approved the Gas Accord settlement agreement (Gas Accord) which restructured the Utility's gas services and its role in the gas market. Among other matters, the Gas Accord separated, or "unbundled," the rates for the Utility's gas transmission services from its distribution services. As a result, the Utility's customers may buy gas directly from competing suppliers and purchase transmission-only and distribution-only services from the Utility. Most of the Utility's industrial and larger commercial customers (noncore customers) now purchase their gas from marketers and brokers. Substantially all residential and smaller commercial customers (core customers) buy gas as well as transmission and distribution services from the Utility as a bundled service. For more information about the Gas Accord and regulatory changes affecting the California natural gas industry, see "Utility Operations--Gas Utility Operations--Gas Regulatory Framework " below.

Additional information concerning competition and the changing regulatory environment is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Note 2 of the "Notes to Consolidated Financial Statements" beginning on page 40 of the 1999 Annual Report to Shareholders, which information is hereby incorporated by reference.

Regulation of PG&E Corporation

PG&E Corporation and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935 (Holding Company Act). At present, PG&E Corporation has no expectation of becoming a registered holding company under the Holding Company Act.

PG&E Corporation is not a public utility under the laws of California and is not subject to regulation as such by the CPUC. However, the CPUC approval authorizing Pacific Gas and Electric Company to form a holding company was granted 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 is precluded from guaranteeing any obligations of PG&E Corporation without prior written consent from the CPUC, the Utility's dividend policy shall continue to be established by the Utility's Board of Directors as though Pacific Gas and Electric Company were a stand-alone utility company, and the capital requirements of the Utility, as determined to be necessary to meet the Utility's service obligations, shall be given first priority by the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company. The conditions also provide that the Utility shall maintain on average its CPUC-authorized utility capital structure, although it shall have an opportunity to request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.

The CPUC also has adopted complex and detailed rules governing transactions between California's natural gas local distribution and electric utility companies and their non-regulated affiliates. The rules permit non-regulated affiliates of regulated utilities (such as PG&E Energy Services, the non-regulated energy marketing subsidiary of PG&E Corporation) to compete in the affiliated utility's service territory, and also to use the name and logo of their affiliated utility, provided that in California the affiliate includes certain designated disclaimer language which emphasizes the separateness of the entities and that the affiliate is not regulated by the CPUC. The rules also address the separation of regulated utilities and their non-regulated affiliates and information exchange among the affiliates. The rules prohibit the utilities from engaging in certain practices, which would discriminate against energy service providers that compete with the utility's non-regulated affiliates.

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

Regulation of Pacific Gas and Electric Company

State Regulation

The CPUC has jurisdiction to regulate the following utility functions within California: electric distribution service, gas distribution service, and gas transmission service. The CPUC regulates Pacific Gas and Electric Company's rates and conditions of service, sales of securities, dispositions of utility property, rates of return, rates of depreciation, and long-term resource procurement. The CPUC also conducts various reviews of utility performance and 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 and confirmed by the State Senate for six-year terms.

The California Energy Commission (CEC) has the responsibility to make electric-demand forecasts for the state and for specific service territories. Based upon these forecasts, the CEC determines the need for additional energy sources and for conservation programs. The CEC sponsors alternative-energy research and development projects, promotes energy conservation programs, and maintains a statewide plan of action in case of energy shortages. In addition, the CEC certifies power plant sites and related facilities within California. The CEC also administers funding for public purpose research and development, and renewable technologies programs.

Federal Regulation

The FERC regulates electric transmission rates and access, operation of the California Independent System Operator (ISO) and the California Power Exchange (PX), uniform systems of accounts, and electric contracts involving sales of electricity for resale. The FERC also has jurisdiction over the Utility's electric transmission revenue requirements and rates. The FERC also regulates the interstate transportation of natural gas. Further, most of the Utility's hydroelectric facilities are subject to licenses issued by the FERC.

The Nuclear Regulatory Commission (NRC) oversees the licensing, construction, operation, and decommissioning of nuclear facilities, including Diablo Canyon and the nuclear generating unit at Humboldt Bay Power Plant (Unit 3). NRC regulations require extensive monitoring and review of the safety, radiological, and environmental aspects of these facilities.

Licenses and Permits

Pacific Gas and Electric Company obtains a number of permits, authorizations, and licenses in connection with the construction and operation of its generating plants, transmission lines, and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, United States Department of Agriculture--Forest Service permits, FERC hydroelectric facility and transmission line licenses, and NRC licenses are the most 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. Pacific Gas and Electric Company currently has ten hydroelectric projects and one transmission line project undergoing FERC license renewal.

Regulation of the National Energy Group

In addition to Pacific Gas and Electric Company, certain of PG&E Corporation's other subsidiaries that conduct interstate gas transmission and storage and electric wholesale power marketing operations are subject to

FERC jurisdiction. The FERC also has authority to regulate rates for natural gas transportation and storage in interstate commerce. The FERC also regulates certain transportation and storage transactions on the intrastate pipelines pursuant to Section 311 of the Natural Gas Policy Act of 1978.

The Railroad Commission of Texas (RRC) regulates gas utilities, including those owned by PG&E Corporation through PG&E Gas Transmission, Texas Corporation (PG&E GTT), PG&E Gas Transmission Teco, Inc., and other affiliates operating in Texas. The RRC's gas proration rules govern the wellhead production and purchase of gas. Intrastate pipelines can provide intrastate gas transportation at negotiated rates that are presumed just and reasonable. If the criteria for negotiated rates cannot be met, the RRC may assess a cost-of-service-based rate. The RRC also may regulate certain sales of gas. Currently, the price of natural gas sold under a majority of PG&E GTT's gas sales contracts is not regulated by the RRC. All transportation and gathering of gas is subject to the RRC Code of Conduct which prohibits undue discrimination among similarly situated shippers. Further, all transportation of gas, processing of gas, and transportation of natural gas liquids is subject to safety regulations enforced by the RRC and the Texas Natural Resource Conservation Commission.

In addition, the power generation projects that PG&E Gen develops, manages, or owns are subject to differing types of federal regulation depending on the regulatory status of the particular project. Some of these projects are exempt wholesale generators (EWG) under the National Energy Policy Act of 1992, which status exempts the project from regulation under the Holding Company Act. EWG status is granted by the FERC upon application by the project. Some projects have received authority from the FERC to charge market-based rates for the power they sell, rather than traditional cost-based rates. Many of PG&E Gen's affiliated projects are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). QF status exempts the project from regulation under various federal and state laws concerning the electric industry. PG&E Gen's projects are also subject to various federal, state, and local regulations concerning siting and environmental matters.

PG&E Corporation's indirect subsidiary USGen New England, Inc. (USGenNE) acquired the electric generating facilities of the New England Electric System (NEES) in September 1998. USGenNE also is subject to numerous federal, state, and local statutes and regulations. USGenNE sells at wholesale all of the electricity it generates, as well as electricity it purchases from third parties under existing power sales agreements. Under the Federal Power Act (FPA), the FERC regulates these wholesale sales. The FERC has approved USGenNE's rate schedule as a market-based schedule and, accordingly, the FERC granted USGenNE waivers of certain other requirements that otherwise are imposed on utilities with cost-based rate schedules. In addition, USGenNE owns and operates a number of hydroelectric and pumped storage projects that are licensed by the FERC. These licenses expire periodically and the projects must be relicensed at that time. USGenNE's licenses for these hydroelectric projects expire over a period from 2001 to 2020. Before expiration of any one of the hydroelectric licenses, there is an opportunity for the existing licensee (as well as others interested in owning and operating the project) to apply for, and obtain, a new license.

USGenNE also is subject to limited regulation by certain state public utility commissions located in states where USGenNE owns and operates electric generating facilities. This regulation does not extend to its rates, which are regulated exclusively by the FERC, and the scope of this regulation has been substantially limited by various legislative initiatives.

Other regulatory matters are described throughout this report.

Risk Management Programs

PG&E Corporation has an officer-level Risk Management Committee and has adopted a Risk Management Policy, approved by the Board of Directors of PG&E Corporation, for trading and risk management activities. The Risk Management Committee oversees implementation of the policy, approves the trading and risk management policies of subsidiaries, and monitors compliance with the policy.

The Risk Management Policy allows derivatives to be used for both hedging and non-hedging purposes. (A derivative is a contract whose value is dependent on or derived from the value of some underlying asset.) PG&E Corporation uses derivatives for hedging purposes primarily to offset underlying commodity price risks. PG&E Corporation also participates in markets using derivatives to gather market intelligence, create liquidity, maintain a market presence, and take a market view. Such derivatives include forward contracts, futures, swaps, and options. The Risk Management Policy and the trading and risk management policies of PG&E Corporation's subsidiaries prohibit the use of derivatives whose payment formula includes a multiple of some underlying asset. The Risk Management Committee also monitors the trading and risk management of PG&E ET, consistent with PG&E Corporation's Risk Management Policy. See "National Energy Group--Energy Trading."

The CPUC has authorized Pacific Gas and Electric Company to trade natural gas-based financial instruments to manage price and revenue risks associated with its natural gas transmission and storage assets, subject to certain conditions. The CPUC also has authorized the Utility to trade natural gas-based financial instruments to hedge the gas commodity price swings in serving core gas customers. In May 1999, the PX obtained FERC approval to operate the "block forward market" which offers parties the ability to buy and sell contracts to purchase electricity in the future at prices set in the contracts. The Utility sought and obtained CPUC authority to participate in the PX block forward market for contracts that call for delivery of the purchased electricity by October 31, 2000, as well as to recover costs (such as gain/losses and transaction fees) associated with its participation in this market.

Additional information concerning risk management activities and the financial impact of risk management activities on PG&E Corporation and Pacific Gas and Electric Company is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5 and in Notes 1, 3, and 4 of the "Notes to Consolidated Financial Statements" beginning on pages 36, 45, and 47, respectively, of the 1999 Annual Report to Shareholders, which information is hereby incorporated by reference.

UTILITY OPERATIONS

Pacific Gas and Electric Company provides regulated electric and gas distribution and transmission services in Northern and Central California. The Utility's service territory covers 70,000 square miles with an estimated population of approximately 13 million and includes all or portions of 48 of California's 58 counties. The area's diverse economy includes aerospace, electronics, financial services, food processing, petroleum refining, agriculture, and tourism.

Ratemaking Mechanisms

The ratemaking mechanisms affecting both electricity and gas distribution operations are discussed below.

General Rate Case. The CPUC authorizes an amount, known as "base revenues," to be collected from ratepayers to recover Pacific Gas and Electric Company's basic business and operational costs for its gas and electric distribution operations. Base revenues, which include non-fuel-related operating and maintenance costs, depreciation, taxes, and a return on invested capital, currently are authorized by the CPUC in General Rate Case (GRC) proceedings. During the GRC, which occurs every three years, the CPUC examines the Utility's costs and operations to determine the amount of base revenue requirement the Utility is authorized to collect from customers through base revenues. The revenue requirement is forecasted on the basis of a specified test year. (The return component of the Utility's revenue requirement is computed using the overall cost of capital authorized in other proceedings.) Following the revenue requirement phase of a GRC, the CPUC conducts a rate design phase, which allocates revenue requirements and establishes rate levels for the different classes of customers. On February 17, 2000, the CPUC issued a decision in the Utility's GRC for the period 1999-2001, further discussed below. The decision also orders that the Utility file a 2002 GRC, so that the revenue requirements established in the 2002 GRC will be the starting point for a future performance based ratemaking (PBR) mechanism (discussed below) that is intended to eventually replace the GRC mechanism and cost of capital proceedings.

Cost of Capital. Each year, the Utility files an application with the CPUC to determine the authorized rate of return that the Utility may earn on its electric and gas distribution assets and recover from ratepayers. In November 1999, the Utility filed its 2000 cost of capital application. To reflect increasing interest rates, the Utility has requested a return on equity (ROE) of 12.5% and an overall rate of return of 9.76% as compared to its 1999 authorized rates of 10.6% ROE and 8.75% overall rate of return. The Utility has not requested any change in its current authorized capital structure of 46.2% long-term debt, 5.8% preferred stock, and 48% common equity. If granted, the requested ROE would increase electric distribution revenues by approximately $36.6 million and natural gas distribution revenues by approximately $127.8 million based upon the rate base authorized in the 1999 GRC. The Utility requested that a final CPUC decision be issued in June 2000. On February 17, 2000, the CPUC issued a decision to allow the final CPUC decision, when it is adopted, to be effective retroactively to February 17, 2000. The return on the Utility's electric transmission-related assets will be determined by the FERC in 2000. The return on the Utility's natural gas transmission and storage business was incorporated in rates established in the Gas Accord settlement. See "Gas Ratemaking--Gas Accord" below. The authorized ROE for the Utility's remaining generation assets, including Diablo Canyon, is 6.77% throughout the transition period.

Electric and Gas Distribution Performance-Based Ratemaking. In November 1998, the Utility filed an application with the CPUC to establish performance-based ratemaking (PBR) for electric and gas distribution services. The proposed distribution PBR would establish electric and gas distribution revenue requirements for the year in which PBR is approved to 2004 taking the place of the GRC and cost of capital proceedings for these years. The Utility proposed that the revenue requirement for the year 2000 be determined by applying a formula, based principally on inflation and productivity factors, to the 1999 GRC authorized revenue requirement. In subsequent years, the formula would be applied to the previous year's authorized revenue requirement. The proposed PBR also includes a sharing mechanism for earnings that are significantly above or below the authorized cost of capital, and a framework for rewards and penalties based upon the achievement of various performance measures.

The final decision in the GRC requires the Utility to go forward with the performance rewards/penalties framework of its PBR proposal, but it requires a 2002 GRC before implementing the PBR mechanism that determines future revenue requirements based principally on inflation and productivity factors. The starting point for the PBR mechanism will be the revenue requirements established in the required 2002 GRC. In any event, after the transition period, the Utility's earnings from its electric distribution operations will be subject to volatility as a result of sales fluctuations.

Annual Earnings Assessment Proceeding. The Annual Earnings Assessment Proceeding (AEAP) determines shareholder incentives to be earned for Pacific Gas and Electric Company's demand side management (DSM) programs. The Utility was authorized to collect $15.9 million in incentive payments during 1999. The Utility has filed an application seeking $28.7 million in incentive payments relating to 1998 energy efficiency and low-income assistance programs, and DSM programs from other years to be paid in 2000. After consolidating the adjusted incentive payment installments from prior years, the net revenue change in 2000 from DSM shareholder incentives should be an electric increase of approximately $2.47 million and a gas decrease of approximately $0.75 million assuming the Utility's incentive claims are approved. The 1999 AEAP decision is expected in the second quarter of 2000.

Catastrophic Event Memorandum Account. The Catastrophic Event Memorandum Account (CEMA) allows Pacific Gas and Electric Company to track costs incurred in connection with catastrophic events. On January 7, 1999, the Utility filed an application with the CPUC in its first CEMA proceeding requesting increases in electric and gas revenue requirements of $60.1 million and $15.8 million, respectively, for costs incurred for several emergencies, including the 1991 Oakland Hills Fire and 1998 storms. In September 1999, the Utility entered into a settlement agreement providing for a $59 million increase in electric distribution revenue requirement and a $11 million increase in gas distribution revenue requirement effective January 1, 2000. A CPUC decision is expected in early 2000.

Electric Ratemaking

The California electric industry restructuring legislation provided for a transition period during which electric customer rates remain frozen. Any change in the Utility's electric revenue requirements resulting from the items discussed below will not change electric customer rates. Under the electric rate freeze, the portion of total actual revenue that exceeds authorized base revenues and certain other authorized revenue requirements and costs is available to recover transition costs during the transition period. Transition costs are certain generation-related costs that prove to be uneconomic under the new competitive generation market. (See "Electric Utility Operations--California Electric Industry Restructuring--Recovery of Transition Costs.") Therefore, increases in base revenues would reduce the amount of revenue available to recover transition costs. Conversely, decreases in base revenues would increase revenue available from frozen rates for recovery of transition costs. The transition period will end the earlier of December 31, 2001, or when the Utility has recovered its eligible transition costs. The electric rate freeze will end the earlier of March 31, 2002, or when the Utility has recovered its eligible transition costs.

General Rate Case. On February 17, 2000, the CPUC issued a decision in the Utility's GRC for the period 1999-2001. The decision is retroactive to January 1, 1999. The CPUC authorized increases in base revenues for the Utility's electric distribution function of $377 million over base revenues authorized in 1996.

Revenue Adjustment Proceeding. On January 1, 1998, the Transition Revenue Account (TRA) was established. The TRA is credited with total revenue collected from ratepayers through frozen rates. From this total revenue the following items are subtracted: (1) revenues collected for transmission services and for the payment of rate reduction bond debt service, (2) the authorized revenue requirement for distribution services, public purpose programs, and nuclear decommissioning costs, and (3) electric industry restructuring implementation costs, energy procurement costs, and other costs. Remaining revenues, if any, are transferred to the Transition Cost Balancing Account (TCBA) to offset transition costs. The CPUC established a separate annual proceeding, the Revenue Adjustment Proceeding (RAP), to review and verify the amounts recorded in the TRA, and to verify each electric utility's authorized revenue requirements, including any necessary adjustments to reflect the revenue requirements which are approved in other proceedings. The RAP also establishes revenue allocation and rate design, and identifies all electric balancing and memorandum accounts for continued retention or elimination. In June 1999, the CPUC issued a decision in the Utility's first RAP that, among other things, adopted an agreement between the Utility and the CPUC's Office of Ratepayer Advocates (ORA) that resolved several rate allocation and rate design issues, eliminated certain balancing and memorandum accounts, and allows the recovery of entries made into the TRA from January 1 through May 31, 1998 and certain other balancing accounts, subject to CPUC audit. On August 9, 1999, the Utility filed its application in the 1999 RAP addressing revenues and costs recorded in the TRA from June 1, 1998 through June 30, 1999. A CPUC decision on this application is expected in late 2000.

Annual Transition Cost Proceeding. The Annual Transition Cost Proceeding (ATCP), applicable to all California investor owned electric utilities, was established to verify the accounting and recording of costs and revenues in the TCBA and ensure that only eligible transition costs have been entered. The TCBA tracks the revenues available to offset transition costs, including the accelerated recovery of plant balances, and other generation-related assets and obligations. Transition costs will receive a limited "reasonableness" review. On September 1, 1998, the Utility filed its application in the 1998 ATCP requesting that $1.8 billion of costs recorded in the TCBA from January 1 through June 30, 1998 be approved as eligible for recovery as transition costs. In July 1999, PG&E and ORA filed a joint motion with the CPUC for approval of a settlement that recommends that the CPUC approve substantially all costs requested by the Utility. On February 17, 2000, the CPUC issued a decision which accepts the settlement in its entirety, and decides most of the other issues in the case in the Utility's favor. Under the final decision, on a prospective basis, the utilities are required to assess the estimated market value of their remaining non-nuclear generating assets, including the land associated with those assets, on an aggregate basis at a value not less than the net book value of those assets and to credit the TCBA with the estimated value. The decision encourages the utilities to base such estimates on realistic assessments of the market value of the assets. The final decision did not adopt a recommendation contained in a previously issued proposed decision to establish a new regulatory asset account that would allow a true-up when the estimated market value is greater than actual market value. However, the decision states that crediting the TCBA with the aggregate net book value of the remaining non-nuclear generating assets is a conservative approach and remedies any concerns regarding the lack of a true-up. The decision provides that if the estimated market valuation is less than book value for any individual asset, accelerated amortization of the associated transition costs will continue until final market valuation of the asset occurs through sale, appraisal, or other divestiture. If the final value of the assets, determined through sale, appraisal or other divestiture, is higher than the estimate, the excess amount would be used to pay remaining transition costs, if any. The utilities are required to file the adjusted entries to their respective TCBA based on the estimated market values with the CPUC by March 9, 2000. The filing will become effective after appropriate review by the CPUC's Energy Division and the TCBA entries are subject to review in the next ATCP. On September 1, 1999, the Utility filed its 1999 ATCP application requesting that $2.6 billion recorded in the TCBA from July 1, 1998, through June 30, 1999, be approved as eligible for recovery as transition costs.

Electric Industry Restructuring Implementation Costs. Under AB 1890, certain electric industry restructuring implementation costs found reasonable by the CPUC may be recovered from electric customers. In May 1999, the CPUC approved a multi-party settlement agreement that, among other things, permits the Utility to recover 1997 and 1998 restructuring implementation costs of $41.3 million (reflecting a reduction of $10 million from the Utility's requested revenue requirement). In addition, the Utility is authorized to recover in its TRA costs related to the Consumer Education Program and the Electric Education Trust funded by the Utility and FERC-approved ISO and PX development and start-up costs. At the end of the transition period, if recovery of these restructuring implementation costs recorded in the TRA displaces recovery of transition costs recorded in the TCBA, the Utility may recover up to $95 million of such displaced transition costs after the transition period.

As part of the settlement agreement, the CPUC also authorized the Utility to establish the Electric Restructuring Costs Account (ERCA) to record the restructuring implementation costs that were removed from its 1999 GRC revenue requirement request, any unanticipated restructuring costs incurred as a result of directives from the CPUC or the FERC, and certain other costs. The reasonableness of the entries made in the ERCA and the recovery of these costs will be made through a separate application by the Utility in 2000.

Revenues from Must-Run Contracts. The ISO has designated certain units at electric generation facilities as necessary to remain available to maintain the reliability of the electric transmission system. These units are called "must-run" units. In general, the ISO dispatches these units under cost-based contracts regulated by the FERC that allow the owners to recover a portion of fixed and operating costs of the must-run units. The owners of must-run units choose among two different forms of must-run contract, both of which cover operating costs. One form provides payments of a percentage of the unit's fixed cost revenue requirement and does not limit market participation. The other form provides 100% fixed cost recovery but allows only very restricted market participation. The Utility's two remaining fossil-fueled power plants (Hunters Point and Humboldt Bay) and three of its hydroelectric generation facilities are under must-run contracts. The form of must-run contract chosen for all of these facilities (except Hunters Point) is the one that does not limit market participation. The Utility currently receives approximately $100 million per year as payments under these must-run contracts, plus fuel costs. In addition, the Utility has the opportunity to earn market revenues for all of these plants except Hunters Point when the ISO has not dispatched the plant. The Utility has filed an application with the CPUC to determine the market value of its hydroelectric generation facilities and related assets through an open competitive auction.

FERC Transmission Owner Rate Case. The ISO controls most of the state's electric transmission facilities. The Utility serves as the scheduling coordinator to schedule transmission with the ISO to facilitate continuing service under wholesale transmission contracts that the Utility entered into before the ISO was established. The ISO bills the Utility for providing certain services associated with these contracts. These ISO charges are referred to as the "scheduling coordinator costs." As part of the Utility's Transmission Owner rate case filed at the FERC, the Utility established a balancing account, the Transmission Revenue Balancing Account (TRBA), to record these scheduling coordinator costs in order to recover these costs through transmission rates. Certain transmission-related revenues collected by the ISO and paid to the Utility are also recorded in the TRBA. Through December 31, 1999, the Utility has recorded approximately $39 million of these scheduling coordinator costs in the TRBA. (The Utility has also disputed approximately $22.5 million of these costs as incorrectly billed by the ISO. Any refunds that ultimately may be made by the ISO would be credited to the TRBA.). On September 1, 1999, a proposed decision was issued denying recovery of these scheduling coordinator costs. The proposed decision is subject to change by the FERC in its final decision. The FERC is expected to issue a final decision sometime in 2000. On January 11, 2000, the FERC accepted a proposal by the Utility to establish the Scheduled Coordinator Services (SCS) Tariff which would act as a back-up mechanism for recovery of the scheduling coordinator costs if the FERC ultimately decides that these costs may not be recovered in the TRBA. The FERC also conditionally granted the Utility's request that the SCS Tariff be effective retroactive to March 31, 1998, but the FERC suspended the procedural schedule until the final decision is issued regarding the inclusion of scheduling coordinator costs in the TRBA.

AB 1890 Electric Base Revenue Increase. AB 1890 provided for an increase in the Utility's electric base revenues for 1997 and 1998, for enhancement of transmission and distribution system safety and reliability. The CPUC authorized a 1997 base revenue increase of $164 million. For 1998, the CPUC authorized an additional base revenue increase of $77 million. The CPUC will determine how much of the authorized increases were actually spent on system safety and reliability during 1997 and 1998, and adjust the amounts downward if necessary. The Utility claims that it overspent the 1997 authorized revenue requirement by approximately $11.8 million and that the Utility underspent 1998 incremental revenues by approximately $6.5 million. The Utility has proposed that the underspent amount be credited to TRA revenues. The CPUC's Office of Ratepayer Advocate (ORA) has recommended that $88.4 million in expenditures for 1997 and 1998 be disallowed. The Utility Reform Network (TURN) has recommended an additional $14 million disallowance for a total recommended disallowance for 1997 and 1998 expenditures of $102.4 million. The Utility opposed the recommended disallowances and hearings were held in October 1999. A proposed decision is not expected until the first quarter of 2000. Any proposed decision would be subject to comment by the parties and change by the CPUC before a final decision is issued.

Electric Transmission Revenues. Since April 1998, all electric transmission revenues are authorized by the FERC. During 1998 and 1999, the FERC issued orders that put into effect various rates to recover electric transmission costs from the Utility's former bundled rate transmission customers. All 1998 and 1999 rates are subject to refund, pending final decisions. In April 1999, the Utility filed a settlement with the FERC which, if approved, would allow the Utility to recover $345 million for the period of April 1998 through May 1999. In May 1999, the FERC accepted, subject to refund, the Utility's March 1999 request to begin recovering, as of May 31, 1999, $324 million annually. In October 1999, the FERC accepted, subject to refund, the Utility's September 1999 request to increase revenues to $370 million annually beginning in April 2000.

Electric Deferred Refund Account (EDRA). In December 1996, the CPUC issued a decision establishing an EDRA. The CPUC ordered the Utility to place into the EDRA credits for CPUC-ordered electric disallowances, the utility electric generation share of gas disallowances ordered by the CPUC or the FERC, and amounts resulting from reasonableness disputes or fuel-related cost refunds made to the Utility based on regulatory agency decisions, plus interest charges. In February 2000, the Utility refunded approximately $25 million of EDRA refunds to customers, which included a refund of unspent research, development, and demonstration funds.

Post-Transition Period Ratemaking Proceeding. In October 1999, the CPUC issued a decision in the Utility's post-transition period ratemaking proceeding. Among other matters, the CPUC decision addresses the mechanisms for ending the current electric rate freeze and for establishing post-transition period accounting mechanisms and rates. The decision prohibits the Utility from collecting after the rate freeze any electric costs incurred during the rate freeze but not recovered during the rate freeze, including costs that are not transition costs and not related to generation assets such as under-collected accounting balances relating to power purchases. The decision also requires the discontinuance of Diablo Canyon's performance-based ratemaking, the incremental cost incentive price (ICIP) mechanism, at the end of the transition period. Instead, after the transition period, Diablo Canyon generation must be sold at the prevailing market price for power. The Utility has filed an application for rehearing of the CPUC's decision.

In the decision, the CPUC also established the Purchased Electric Commodity Account (PECA) for the Utility to track energy costs after the rate freeze and transition period end. The CPUC intends to explore other ratemaking issues, including whether dollar-for-dollar recovery of energy costs is appropriate, in the second phase of the post-transition electric ratemaking proceeding. There are three primary options for the future regulatory framework for utility electric energy procurement cost recovery after the rate freeze: (1) a CPUC-defined procurement practice, that if followed by the Utility, would pass through costs without the need for reasonableness reviews, (2) a pass through of costs subject to after-the-fact reasonableness reviews, or (3) a procurement incentive mechanisms with rewards and penalties determined based on the Utility's energy purchasing performance compared to a benchmark. The Utility proposed adoption of either a defined procurement practice or a procurement incentive mechanism, neither of which would involve reasonableness reviews. The volatility of earnings and risk exposure of the Utility related to post-transition period purchases of electricity is dependent on which of these options, or some other approach, is adopted.

A decision in the second phase of the proceeding is expected in the first quarter 2000, addressing certain other post-transition period ratemaking issues including, among others, incentive mechanisms for commodity purchases and the allocation of certain transition costs that are recoverable after the transition period.

Additional information about the financial impact of the end of the rate freeze and the end of the transition period on the Utility and PG&E Corporation is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5.

Gas Ratemaking

Gas Accord. The Gas Accord separated or "unbundled" the Utility's gas transmission services from its distribution services, changed the terms of service and rate structure for gas transportation, increased the opportunity for core customers to purchase gas from competing suppliers, established a form of incentive mechanism to measure the reasonableness of core procurement costs, and established gas transmission and storage rates through 2002. Additional information about the Gas Accord is provided below in "Utility Operations--Gas Utility Operations" and in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5.

General Rate Case. On February 17, 2000, the CPUC issued a decision in the Utility's GRC for the period 1999-2001. The decision is retroactive to January 1, 1999. The CPUC authorized increases in base revenues for the Utility's gas distribution function of approximately $93 million over base revenues authorized in 1996.

The Biennial Cost Allocation Proceeding (BCAP). The BCAP remains the proceeding in which distribution costs and balancing account balances are allocated to customers. The BCAP normally occurs every two years and is updated in the interim year for purposes of amortizing any accumulation in the balancing accounts. Balancing accounts for natural gas costs accumulate differences between the actual recovery of gas costs and the revenues designed for recovery of such costs. Balancing accounts for sales volumes accumulate differences between authorized and actual base revenues. In June 1998, the CPUC adopted a decision in the 1998 BCAP granting an annual $97.8 million revenue requirement decrease effective September 1, 1998, compared to revenues established by the Gas Accord on March 1, 1998. The overall annual revenue requirement for the two-year BCAP period (September 1, 1998, through August 31, 2000) is approximately $1.5 billion, of which an annual average of approximately $102 million is allocated for the collection of balancing accounts. The Utility plans to file its 2000 BCAP application in the first half of 2000.

Electric Utility Operations

California Electric Industry Restructuring

As a result of California electric industry restructuring, the electric generation function of traditional utilities has been opened up to competition, giving electric customers of investor-owned utilities (such as Pacific Gas and Electric Company) the choice of continuing to purchase electricity from investor-owned utilities or purchasing electricity from alternative providers (including unregulated power generators and unregulated retail electricity providers such as marketers, brokers, and aggregators). Purchasing electricity from an alternative generation provider is called "direct access." For those customers who have not chosen an alternative generation provider, investor-owned utilities continue to be the generation provider. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including those customers who choose direct access.

The California Independent System Operator and the California Power Exchange. To create a competitive generation market, the PX and the ISO were established and began operating on March 31, 1998. The FERC has jurisdiction over both the ISO and the PX.

The ISO operates and controls most of the state's electric transmission facilities (which continue to be owned and maintained by the California utilities) and provides comparable open access to electric transmission service. The ISO accepts balanced supply and load schedules from market participants and manages the availability of electric transmission on a statewide basis for these transactions. The ISO also purchases necessary generation and ancillary services to maintain grid reliability. The ISO is required to ensure reliable transmission services consistent with planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council. Oversight of utility distribution systems remains with the CPUC.

The PX provides a competitive auction process to establish transparent market clearing prices for electricity in the markets operated by the PX. During the transition period, the Utility is required to sell into the PX all of its generated electric power. "Must-take" generation resources, such as nuclear generation from Diablo Canyon, electric power generated by QFs and electricity that the Utility is required to purchase under existing contractual commitments, also are scheduled through the PX. During the transition period, the Utility must purchase all electric power for its retail customers through the PX. Customers who buy power directly from non-regulated suppliers pay for that generation based upon negotiated contracts. The PX sets a market-clearing price for electricity by matching all demand load bids with supply bids ranked from lowest to highest. The highest-accepted generation supply bid used to serve load sets the PX market-clearing price for electricity.

After the transition period, the Utility may continue to schedule its must-take generation resources into the PX. It is unsettled whether the Utility will be required to continue purchasing its electric power for its retail customers through the PX after the transition period. The Utility expects that the CPUC will address the issue of whether the purchase obligation will continue through December 31, 2001, if the Utility's rate freeze ends before that date, in the second phase of the Utility's post-transition period ratemaking proceeding in the first quarter of 2000. Some parties have argued that the utilities' purchase obligation may need to continue beyond December 31, 2001, depending on market conditions. See "Ratemaking Mechanisms--Electric Ratemaking--Post-Transition Period Ratemaking Proceeding" above.

The ISO and PX are California public benefit non-profit corporations. Each has a Governing Board that includes representatives of investor-owned utility transmission systems, publicly owned utility transmission systems, non-utility electricity sellers, public buyers and sellers, private buyers and sellers, industrial end-users, commercial end-users, residential end-users, agricultural end-users, public interest groups, and non-market participant representatives. The ISO and PX currently are overseen by a five-member Electricity Oversight Board (EOB) that appoints the members of the ISO and PX Governing Boards. However, this appointment power was rejected by the FERC. Subsequently the California Legislature passed, and the Governor signed, Senate Bill (SB) 96 which redefined the relationship between the EOB and the ISO and PX. SB 96 limits the EOB's appointment power to representatives of those classes that represent California consumers' interests. The ISO or PX Governing Boards confirm all other appointments. SB 96 has been accepted in principle by the FERC. Bylaw amendments implementing SB 96 are pending before the FERC for the PX and the ISO currently is circulating draft bylaw amendments among its stakeholders.

Voluntary Generation Asset Divestiture. California utilities, including Pacific Gas and Electric Company, have voluntarily begun divesting some of their generation assets. In 1998, the Utility sold three of its fossil-fueled electric generating plants located at Morro Bay, Moss Landing, and Oakland, California. In 1999, the Utility also sold three fossil-fueled generating facilities (the Pittsburg and Contra Costa power plants located in Contra Costa County, and the Potrero power plant in San Francisco) and its geothermal generating facilities (The Geysers Power Plant located in Lake and Sonoma Counties). The Utility has retained liability for required environmental remediation of any pre-closing soil or groundwater contamination at these plants.

In September 1999, the Utility filed an application with the CPUC to determine the market value of the Utility's hydroelectric generation facilities and related assets through an open competitive auction. The Utility proposes to use an auction process similar to the one previously used in the sale of the Utility's fossil fueled and geothermal plants. Under the process proposed in the application. PG&E Gen would be permitted to participate in the auction on the same basis as other bidders. The sale of the hydroelectric facilities would be subject to certain conditions, including the transfer or re-issuance of various permits and licenses by the FERC and other agencies. On January 13, 2000, the CPUC issued a ruling which separates the proceeding into two concurrent phases: one to review the potential environmental impacts of the proposed auction under the California Environmental Quality Act (CEQA) and a second to determine whether the Utility's auction proposal, or some other alternative to the proposal, is in the public interest. The ruling sets a procedural schedule which calls for a final CPUC decision on the Utility's auction proposal by October 19, 2000, and a final environmental impact report published in November 2000. The schedule calls for the auction, if approved, to begin in early November 2000 and end in early January 2001. The schedule anticipates that the divestiture process would be closed by June 1, 2001. Finally, the ruling prohibits the Utility from withdrawing its application without express CPUC authority. It is uncertain whether the CPUC will ultimately approve the Utility's auction proposal. Additional information about the potential financial impact of the proposed auction on the Utility and PG&E Corporation is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5.

As required by AB 1890, Utility employees, under two-year operations and maintenance agreements with the new owners, will continue to operate and maintain the power plants that have been sold. To the extent that payments to the Utility under these agreements exceed the Utility's cost of operating the plants, the additional revenue would be given to ratepayers. Conversely, to the extent the Utility's operating costs exceed the revenues from these agreements, the Utility absorbs these losses in earnings.

Recovery of Transition Costs. As market-based revenues may not be sufficient to recover certain of the Utility's generation costs, AB 1890 provides the investor-owned utilities the opportunity to recover such uneconomic generation costs (called transition costs) for a certain period of time (the transition period). Some transition costs may be recovered after the transition period. Costs eligible for recovery as transition costs, as determined by the CPUC, include (1) above-market sunk costs (i.e., costs associated with utility generating facilities that are fixed and unavoidable and that were included in customer rates on December 20, 1995) and future sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from QFs and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods to be included in rates in subsequent periods.) Transition costs are eligible for recovery from all customers (with certain exceptions) through a nonbypassable competition transition charge, or CTC, included as part of rates. Transition costs that are disallowed by the CPUC for collection from customers will be written off.

As a prerequisite to any consumer obtaining direct access services, the consumer must agree to pay its applicable nonbypassable CTC. Most transition costs must be recovered by December 31, 2001, although certain transition costs may be recovered after December 31, 2001. These costs include (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, (3) up to $95 million of transition costs to the extent that the recovery of such costs during the transition period was displaced by the recovery of electric industry restructuring implementation costs, and (4) transition costs financed by the issuance of rate reduction bonds. In addition, nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission the nuclear facility.

The total amount of sunk costs to be included as transition costs will be based on the aggregate of above-market and below-market values of utility-owned generation assets and obligations. Under AB 1890, valuation of generation-related assets through appraisal, sale, or other divestiture must be completed by December 31, 2001. The value of seven of the Utility's power plants was established when these facilities were sold to third parties. In October 1998, the CPUC ruled that the market value of the Hunters Point power plant is zero. In September 1999, the Utility filed an application with the CPUC to determine the market value of the Utility's hydroelectric generating facilities and related costs through an open competitive auction.

Retail Direct Access. Customers participating in direct access may purchase their electric power directly either through (1) competing non-utility retail electric providers such as brokers, marketers, aggregators, or other retailers, or (2) direct negotiated contracts with electric generators. All customers (with limited exceptions), whether they choose direct access or not, must pay the nonbypassable CTC, which will be collected by their distribution utility in connection with recovery of the utilities' transition costs.

Utilities began accepting requests for direct access in November 1997 to become effective after direct access began. As of February 17, 2000, Pacific Gas and Electric Company had transferred 94,454 customers to direct access. The CPUC requires that electric customers with an electricity demand, or load, of 50 kilowatts (kW) or more must have meters that are capable of providing hourly data in order to participate in direct access. Those customers with a load less than 50 kW may participate in direct access either through "load profiling" or by installing an hourly meter. (Load profiling approximates the pattern of electricity usage for a given customer class and provides the equivalent of hourly meter reads.) The customer is responsible for the cost of the meter and the meter installation.

Energy service providers supplying the direct access market may choose one of three billing options: (1) consolidated energy supplier billing, under which the utility bills the energy supplier for the services provided directly by the utility to the customer, and the supplier, in turn, provides a consolidated bill to the customer, (2) consolidated distribution company billing, under which the utility places the supplier's energy charge on a distribution bill, or (3) dual billing, under which the energy supplier and the utility bill separately for their own services. Since January 1, 1999, energy service providers may provide metering to all of their customers.

During 1999, the Utility continued its efforts to develop and implement changes to its business processes and systems, including customer information and billing systems, to accommodate direct access. To the extent the Utility is unable to successfully and timely develop and implement such changes, there could be an adverse impact on PG&E Corporation's and the Utility's future results of operations.

Rate Levels and Rate Reduction Bonds. As required by AB 1890, electric rates for all customers have been frozen at the level in effect on June 10, 1996, and, beginning January 1, 1998, rates for residential and small commercial customers were reduced by 10% from 1996 levels. The electric rate freeze and electric rate reduction will continue throughout the transition period. In 1997, the Utility refinanced the expected 10% rate reduction with the proceeds from rate reduction bonds. On December 8, 1997, a special purpose entity established by the California Infrastructure and Economic Development Bank issued $2.9 billion (the expected revenue reduction from the rate decrease) of rate reduction bonds on behalf of a wholly owned subsidiary of the Utility. The bonds were issued in eight classes with maturities ranging from 10 months to 10 years, and bearing interest at rates ranging from 5.94% to 6.48%. The Utility is collecting from residential and small commercial customers a separate nonbypassable charge on behalf of the bondholders to recover principal, interest, and related costs over the life of the bonds. The bond proceeds were used by the wholly owned subsidiary to purchase from the Utility the right to be paid the revenues from this separate charge. The bonds are secured by the future revenue from the separate charge and not by the Utility's assets. While the bonds are reflected as long-term debt on the Utility's balance sheet, the Utility's creditors do not have any recourse to the revenues from the separate charge. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service will not increase the Utility customers' electric rates. If the transition period ends before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Public Purpose Programs. Under AB 1890, the Utility is authorized to collect not less than $198 million in a separate nonbypassable charge included in frozen electric rates to fund Utility and other entities' investments in four public purpose programs: (1) cost-effective energy efficiency and energy conservation programs, (2), research, development and demonstration programs, (3), renewable energy resources programs, and (4) low-income electricity programs including targeted energy efficiency services and rate discounts. Low-income energy efficiency programs are funded at the level of need, but are not to be funded at less than the 1996 level of expenditures. Under this provision of AB 1890, the Utility is obligated to fund through electric rates energy efficiency and conservation programs in an amount not less than $106 million per year, public interest research and development programs at not less than $30 million per year, renewable energy technologies at not less than $48 million per year, and low-income energy efficiency programs at not less than $14 million per year. The Utility also collects funds for the California Alternate Rates for Energy (CARE) low-income discount rate, a rate subsidy paid for by the Utility's other customers, which is currently about $31 million per year.

Under the oversight of the CPUC, the Utility administers both the cost-effective energy efficiency and low-income energy efficiency programs. These two programs are reviewed annually in the Annual Earnings Assessment Proceeding. In March 1999, the CPUC determined that these programs should continue to be administered by investor-owned utilities, subject to CPUC oversight, through 2001. Effective January 1, 2000, Section 327 of the California Public Utilities Code requires utilities to continue to administer low-income energy efficiency programs. In accordance with AB 1890, the California Energy Resources Conservation and Development Commission, (also called the California Energy Commission (CEC)) administers both the public interest research and development program and the renewable energy program on a statewide basis. The Utility transfers $78 million per year to the CEC for these two programs.

Distributed Generation and Electric Distribution Competition. In October 1999, the CPUC issued a decision outlining how the CPUC, in cooperation with other regulatory agencies and the California Legislature, plans to address the issues surrounding distributed generation, electric distribution competition, and the role of the utility distribution companies (such as Pacific Gas and Electric Company) in the competitive retail electricity market. Distributed generation enables siting of electric generation technologies in close proximity to the electric demand (referred to as "load"). The CPUC decision opened a new rulemaking proceeding to examine various issues concerning distributed generation, including interconnection issues, who can own and operate distributed generation, environmental impacts, the role of utility distribution companies, and the rate design and cost allocation issues associated with the deployment of distributed generation facilities. With respect to electric distribution competition, the CPUC directed its staff to deliver a report by April 21, 2000 on the different policy options that the CPUC, in cooperation with the California Legislature, can pursue. Following the issuance of the report, the CPUC expects to open one or more new proceedings to address electric distribution competition and competition in the retail electric market.

Electric Operating Statistics

At December 31, 1999, Pacific Gas and Electric Company served approximately 4.6 million electric distribution customers.

During the transition period, the Utility is required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier. The following table shows the Utility's operating statistics (excluding subsidiaries) for electric energy, including the classification of sales and revenues by type of service.

	1999	1998	1997	1996	1995
Customers (average for the year):					
Residential	4,017,428	3,962,318	3,915,370	3,874,223	3,825,413
Commercial	474,710	469,136	465,461	459,001	454,718
Industrial	1,151	1,093	1,121	1,248	1,253
Agricultural	85,131	85,429	86,359	87,250	88,546
Public street and highway lighting	20,806	18,351	17,955	17,583	17,089
Other electric utilities	0	14	47	28	35
Total	4,599,226	4,536,341	4,486,313	4,439,333	4,387,054
Sales-kWh (in millions):					
Residential	27,739	26,846	25,946	25,458	24,391
Commercial	30,426	28,839	28,887	27,868	27,014
Industrial(1)	16,722	16,327	16,876	15,786	16,879
Agricultural(1)	3,739	3,069	3,932	3,631	3,478
Public street and highway lighting	437	445	446	438	425
Other electric utilities	167	2,358	3,291	1,213	3,172
Total energy delivered	79,230	77,884	79,378	74,394	75,359

Revenues (in thousands):					
Residential	$2,961,788	$2,891,424	$3,082,013	$3,033,613	$2,979,590
Commercial	2,837,111	2,793,336	2,932,560	2,840,101	2,964,568
Industrial	863,951	933,316	1,028,378	1,005,694	1,160,938
Agricultural	391,876	350,445	413,711	396,469	395,531
Public street and highway lighting	49,209	51,195	53,183	55,372	56,154
Other electric utilities	16,501	50,166	118,781	81,855	133,566
Revenues from energy deliveries	7,120,436	7,069,882	7,628,626	7,413,104	7,690,347
Miscellaneous	162,105	161,156	(9,439)	112,303	92,538
Regulatory balancing accounts	(50,780)	(40,408)	71,441	(365,192)	(396,578)
Operating revenues	$7,231,761	$7,190,630	$7,690,628	$7,160,215	$7,386,307

The following table shows certain customer information:

Selected Statistics:	1999	1998	1997	1996	1995
Average annual residential usage (kWh)	6,905	6,776	6,627	6,571	6,377
Average billed revenues per kWh (cents per kWh):					
Residential	10.68	10.77	11.88	11.92	12.22
Commercial	9.32	9.69	10.15	10.19	10.97
Industrial(1)	5.17	5.72	6.09	6.37	6.88
Agricultural(1)	10.48	11.42	10.52	10.92	11.37
Net plant investment per customer ($)	2,388	2,705	3,027	3,198	3,228

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(1) Beginning April 1998, the sales-kWh and average billed revenues per kWh include electricity provided to direct access customers where the Utility does not earn commodity charges.

Electric Generating Capacity

At the beginning of 1999, the Utility's electric generation facilities included five primarily natural gas-fueled steam power plants with 15 units, four combustion turbines, two nuclear power reactor units at Diablo Canyon, 67 hydroelectric powerhouses with 107 units, and the Helms hydroelectric pumped storage plant (Helms) with three units. In 1998, the Utility sold three of its fossil-fueled power plants. In April and May 1999, the Utility sold three of its five remaining fossil-fueled power plants, which include 10 steam units and three combustion turbines, and its geothermal energy complex of 14 units. Together, the seven divested power plants represented 91% of the Utility's fossil-fueled generating capacity and all of its geothermal generating capacity. The facilities generated approximately 31% of the Utility's total electric energy production.

The Utility is committed under long-term contracts to purchase power produced by other generating entities that use a wide array of resources and technologies, including hydroelectric, wind, solar, biomass, geothermal, and cogeneration. In addition, the Utility is interconnected with electric power systems in 14 western states and British Columbia, Canada, for the purposes of buying, selling, and transmitting power.

During the transition period, the Utility is required to bid or schedule into the PX and ISO markets all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators.

Except as otherwise noted below, as of December 31, 1999, Pacific Gas and Electric Company owned and operated the following generating plants, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity kW
Hydroelectric:			
Conventional Plants(1)	16 counties in Northern and Central California	107	2,684,100
Helms Pumped Storage Plant(1)	Fresno	3	1,212,000
Hydroelectric Subtotal		110	3,896,100
Steam Plants:			
Humboldt Bay	Humboldt	2	105,000
Hunters Point(2)	San Francisco	3	377,000
Steam Subtotal		5	482,000
Combustion Turbines:			
Hunters Point(2)	San Francisco	1	52,000
Mobile Turbines(3)	Humboldt and Mendocino	3	45,000
Combustion Turbines Subtotal		4	97,000
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,160,000
Total		121	6,635,100

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(1) In September 1999, the Utility filed an application with the CPUC to determine the market value of the Utility's hydroelectric generating facilities and related assets through an open competitive auction. (See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring" above.)

(2) In July 1998, the Utility reached an agreement with the City and County of San Francisco regarding the Hunters Point fossil-fueled power plant, which the ISO has designated as a "must run" facility. The agreement expresses the Utility's intention to retire the plant when it is no longer needed by the ISO.

(3) Listed to show capability; subject to relocation within the system as required.

Diablo Canyon

Diablo Canyon Operations

Diablo Canyon consists of two nuclear power reactor units, each capable of generating up to approximately 26 million kilowatt-hours (kWh) of electricity per day. Diablo Canyon Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively. The operating license expiration dates for Diablo Canyon Units 1 and 2 are September 2021 and April 2025, respectively. As of December 31, 1999, Diablo Canyon Units 1 and 2 had achieved lifetime capacity factors of 82% and 83%, respectively.

The table below outlines Diablo Canyon's refueling schedule for the next five years. Diablo Canyon refueling outages typically are scheduled every 19 to 21 months. The schedule below assumes that a refueling outage for a unit will last approximately thirty days, depending on the scope of the work required for a particular outage. The schedule is subject to change in the event of unscheduled plant outages.

	2000	2001	2002	2003	2004
Unit 1					
Refueling....................	October		May		February
Startup......................	November		June		March
Unit 2					
Refueling....................		May		February	October
Startup......................		June		March	November

Diablo Canyon Ratemaking

Since January 1, 1997, the Utility's sunk costs in Diablo Canyon are recovered from ratepayers through a sunk cost revenue requirement, at a reduced return on common equity equal to 6.77% that will remain in effect through the end of the transition period. (Sunk costs are costs associated with the facility that are fixed and unavoidable.) The Diablo Canyon sunk costs revenue requirement is being recovered as a transition cost through the TCBA. In connection with the new ratemaking, the CPUC ordered that a financial verification audit of Diablo Canyon plant accounts be performed by an independent accounting firm, and that the CPUC hold a proceeding to review the results of the audit, including any proposed adjustments to Diablo Canyon accounts, following the completion of the audit. On August 31, 1998, an independent accounting firm retained by the CPUC completed its financial verification audit of the December 31, 1996 Diablo Canyon plant accounts. The audit resulted in the issuance of an unqualified opinion. The audit verified that Diablo Canyon sunk costs at December 31, 1996, were $3.3 billion of the total $7.1 billion construction costs. The independent accounting firm also issued an agreed-upon special procedures report, requested by the CPUC, which questioned $200 million of the $3.3 billion sunk costs. The CPUC will review the results of the audit and may seek to make adjustments to Diablo Canyon sunk costs subject to transition cost recovery. At this time, what action the CPUC may take regarding the audit, if any, cannot be predicted.

Also since January 1, 1997, a performance-based Incremental Cost Incentive Price (ICIP) mechanism has been used to recover Diablo Canyon's operating costs and the cost of capital additions incurred after December 31, 1996. The ICIP mechanism establishes a rate per kWh generated by the facility for the period 1997 through 2001. The CPUC-authorized ICIP prices and revenue requirement for Diablo Canyon for 2000 and 2001 are shown below. The ICIP revenues are based on an assumed capacity factor of 83.6%.

	Estimated Total Revenue Requirement	
	2000	2001
ICIP (cents per kWh)	3.43	3.49
Sunk Cost Recovery ($ in millions)	$ 1,197	$ 1,135
ICIP Revenues ($ in millions)	542	552
Total Revenue Requirement ($ in millions)	$ 1,739	$ 1,687

Any variance between ICIP revenues and related costs is reflected in earnings. In October 1999, the CPUC issued a decision that will discontinue the ICIP mechanism after the transition period. After the transition period, Diablo Canyon generation must be sold at the prevailing market price for power. The Utility has filed an application for rehearing of this decision. Further, pursuant to the 1997 CPUC decision establishing the ICIP, the Utility is required to begin sharing 50% of the net benefits of operating Diablo Canyon with ratepayers beginning January 1, 2002. The CPUC may interpret a more recent CPUC decision to require sharing to begin at the end of the transition period. The Utility is required to file an application with the

CPUC in July 2000 with its proposal for the methods to be used in the valuation of the benefits associated with the operation of Diablo Canyon and the mechanism to be used to share these benefits with ratepayers. (See "Utility Operations--Ratemaking Mechanisms--Electric Ratemaking--Post-Transition Period Ratemaking Mechanisms" above.)

Additional information concerning the financial impact of Diablo Canyon ratemaking is included in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Note 2 of the "Notes to Consolidated Financial Statements" beginning on page 40 of the 1999 Annual Report to Shareholders.

Nuclear Fuel Supply and Disposal

Pacific Gas and Electric Company has purchase contracts for, and inventories of, uranium concentrates, uranium hexaflouride, and enriched uranium, as well as one contract for fuel fabrication. Based on current Diablo Canyon operations forecasts and a combination of existing contracts and inventories, the requirement for uranium supply will be met through 2004, the requirement for the conversion of uranium to uranium hexaflouride will be met through 2001, and the requirement for the enrichment of the uranium hexaflouride to enriched uranium will be met through 2002. The fuel fabrication contract for the two units will supply their requirements for the next seven operating cycles of each unit. These contracts are intended to ensure long-term fuel supply, but permit the Utility the flexibility to take advantage of short-term supply opportunities. In most cases, the Utility's nuclear fuel contracts are requirements-based, with the Utility's obligations linked to the continued operation of Diablo Canyon.

Under the Nuclear Waste Policy Act of 1982 (Nuclear Waste Act), the U.S. Department of Energy (DOE) is responsible for the transportation and ultimate long-term disposal of spent nuclear fuel and high-level radioactive waste. Under the Nuclear Waste Act, utilities are required to provide interim storage facilities until permanent storage facilities are provided by the federal government. The Nuclear Waste Act mandates that one or more such permanent disposal sites be in operation by 1998. Consistent with the law, Pacific Gas and Electric Company signed a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities beginning not later than January 1998. However, due to delays in identifying a storage site, the DOE has been unable to meet its contract commitment to begin accepting spent fuel by January 1998. Further, under the DOE's current estimated acceptance schedule for spent fuel, Diablo Canyon's spent fuel may not be accepted by the DOE for interim or permanent storage before 2010, at the earliest. At the projected level of operation for Diablo Canyon, the Utility's facilities are sufficient to store on-site all spent fuel produced through approximately 2006 while maintaining the capability for a full-core off-load. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2006. The Utility is examining options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities, pending disposal or storage at a DOE facility.

In July 1988, the NRC gave final approval to the Utility to store radioactive waste from the nuclear generating unit (Unit 3) at Humboldt Bay Power Plant (Humboldt) at Humboldt before ultimately decommissioning the unit. The Utility has agreed to remove all spent fuel when the federal disposal site is available.

Insurance

Pacific Gas and Electric Company has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). NEIL, which is owned by utilities with nuclear generating facilities, provides insurance coverage against property damage, decontamination, decommissioning, and business interruption and/or extra expenses during prolonged accidental outages for reactor units in commercial operation. Under these insurance policies, if the nuclear generating facility of a member utility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective premium assessments of $15 million (property damage) and $4 million (business interruption), in each case per one-year policy period, if losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. An additional $9.3 billion of coverage is provided by secondary financial protection required by federal law and provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Decommissioning

Pacific Gas and Electric Company's estimated total obligation to decommission and dismantle its nuclear power facilities is $1.6 billion in 1999 dollars ($5.1 billion in future dollars). This estimate, which includes labor, materials, waste disposal charges, and other costs, is based on a 1997 decommissioning cost study. A contingency to capture engineering, regulatory, and business environment changes is included in the total estimated obligation. Actual decommissioning costs are expected to vary from this estimate because of changes in the assumed dates of decommissioning, regulatory requirements, and technology, as well as differences in the amount of labor, materials, and equipment needed to complete decommissioning. The estimated total obligation needed to complete decommissioning is recognized proportionately over the license term of each facility.

Nuclear decommissioning costs recovered in rates are placed in external trust funds. These funds, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the nuclear facilities. The trust funds maintain substantially all of their investments in debt and equity securities. All earnings on the trust fund, net of authorized disbursements from the trusts and management and administrative fees, are reinvested. Monies may not be released from the external trust funds until authorized by the CPUC. In December 1997, the CPUC granted the Utility's request for authority to disburse up to $15.7 million from the Humboldt Bay Power Plant decommissioning trust funds to finance three partial nuclear decommissioning projects at Humboldt Bay Power Plant Unit 3. Accordingly, as of December 31, 1999, $9.3 million (net of taxes) has been disbursed from the Humboldt Bay Power Plant Unit 3 non-tax-qualified trust to reimburse the Utility for nuclear decommissioning expenses associated with the partial decommissioning projects. The remaining $6.4 million of the approved expenses is expected to be funded with associated tax savings.

In its 1999 GRC, Pacific Gas and Electric Company sought approval from the CPUC to use the tax savings resulting from the payment of tax-deductible nuclear decommissioning expenses from the Humboldt Bay Power Plant Unit 3 non-tax-qualified trust to fund nuclear decommissioning work. The CPUC found that the Utility's recommended approach of using the tax benefit to fund decommissioning activity was reasonable and approved the Utility's request.

As of December 31, 1999, the Utility had accumulated external trust funds with an estimated fair value of $1.3 billion, based on quoted market prices and net of deferred taxes on unrealized gains, to be used for the decommissioning of the Utility's nuclear facilities.

The amount recovered in rates for nuclear decommissioning costs is authorized by the CPUC as part of the GRC. The CPUC considers the trusts' asset levels, together with revised earnings and decommissioning cost assumptions, to determine the amount of decommissioning costs it will authorize in rates for contribution to the trusts. The monies contributed to the decommissioning trusts, together with existing trust fund balances and projected earnings, are intended to satisfy the estimated future obligation for decommissioning costs. For the year ended December 31, 1999, annual nuclear decommissioning trust contributions collected in rates were $26.47 million.

Since January 1, 1998, nuclear decommissioning costs, which are not transition costs, have been recovered through a nonbypassable charge that will continue until those costs are fully recovered. Recovery of decommissioning costs may be accelerated to the extent possible under the rate freeze. The CPUC has established a Nuclear Decommissioning Costs Triennial Proceeding to determine the decommissioning costs and to establish the annual revenue requirement and attrition factors over subsequent three-year periods when and if GRCs are discontinued.

Other Electric Resources

QF Generation and Other Power Purchase Contracts

By federal law, Pacific Gas and Electric Company is required to purchase electric energy and capacity provided by independent power producers that are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). The CPUC established a series of QF long-term power purchase contracts and set the applicable terms, conditions, price options, and eligibility requirements. Under these contracts, the Utility is required to make payments only when energy is supplied (an "energy payment") or when capacity commitments are met (a "capacity payment"). Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the nonbypassable CTC. The Utility's contracts with these power producers expire on various dates through 2028. Deliveries from these power producers account for approximately 23% of the Utility's 1999 electric energy requirements and no single contract accounted for more than 5% of the Utility's energy needs.

The Utility has negotiated with several QFs for early termination of their power purchase contracts. For other contracts, the Utility has negotiated with QFs to refrain from producing energy during the remaining term of the higher fixed energy price period under their contract (a "buy-down") or to curtail energy production for shorter periods of time (a "curtailment"). At December 31, 1999, the total discounted future payments due under the renegotiated contracts that are subject to early termination, buy-down or curtailment, was $16 million. Of the $16 million, the Utility has recovered $6.6 million in rates and expects to recover the remaining $9.4 million in future rates.

As of December 31, 1999, the Utility had commitments to purchase approximately 5,200 MW of capacity under CPUC-mandated power purchase agreements. Of the 5,200 MW, approximately 4,500 MW are operational. Development of the majority of the balance is uncertain and it is estimated that very few of the remaining contracts will become operational. The 4,500 MW of operational capacity consists of 2,800 MW from co-generation projects, 700 MW from wind projects, and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar, and hydroelectric.

The Utility also 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 whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. Costs associated with these contracts to purchase power are eligible for recovery by the Utility as transition costs through the collection of the nonbypassable CTC. At December 31, 1999, the undiscounted future minimum payments under these contracts are approximately $32.7 million for each of the years 2000 through 2004 and a total of $280 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately 5.8% of the Utility's 1999 electric energy requirements.

The amount of energy received and the total payments made under all these power purchase contracts were:

	1999	1998	1997
	(in millions)		
Kilowatt-hours received	25,910	25,994	24,389
Energy payments	$ 837	$ 943	$1,157
Capacity payments	$ 539	$ 529	$ 538
Irrigation district and water agency payments	$ 60	$ 53	$ 56

Electric Transmission and Distribution

To transport energy to load centers, Pacific Gas and Electric Company as of December 31, 1999, owned approximately 18,624 circuit miles of interconnected transmission lines of 60 kilovolts (kV) to 500 kV and transmission substations having a capacity of approximately 42,106,600 kilovolt-amperes (kVa), including spares, excluding power plant interconnection facilities. Energy is distributed to customers through approximately 113,289 circuit miles of distribution system and distribution substations having a capacity of approximately 23,773,000 kVa.

In 1998, the utilities relinquished control, but not ownership, of their transmission facilities to the ISO. The ISO commenced operations on March 31, 1998. The ISO, regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. In 1998, the FERC approved the various forms of agreements for must-run facilities that have been entered into between the utilities and the ISO to ensure grid reliability.

The FERC also has approved a proposal from Pacific Gas and Electric Company and the other California utilities that distinguishes between local distribution facilities and transmission facilities. The FERC will have jurisdiction over the transmission facilities as defined in the order and over the transmission aspects of direct access. Most of the Utility's distribution services remain subject to CPUC jurisdiction.

The CPUC is considering whether it should pursue further reforms in the structure and regulatory framework governing electricity distribution service. See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring" above.

During 1999, the Utility and various other parties, including the ISO and the CPUC, issued reports on their investigation into the power outage that occurred on December 8, 1998, in the San Francisco Bay area. In March 1999, the ISO issued its report on the outage that concluded that the Utility's system was designed in accordance with industry standards and responded as expected under the circumstances. The ISO's report identified a number of measures for the Utility to undertake to minimize the likelihood of a similar event occurring in the future. Reports by other parties, including the CPUC, have also recommended corrective measures. Since the outage, the Utility has revised its grounding and switching procedures as preventive measures to minimize the risk that the type of initiating event that caused the outage could occur in the future. On October 20, 1999, the Utility submitted a report to the CPUC describing how its corrective actions implements the ISO's recommendations, and responds to the other parties' recommendations. The CPUC is currently holding workshops to address the issues in the proceeding. After the conclusion of the workshops, the CPUC plans to convene another prehearing conference to discuss how to address any remaining issues.

Gas Utility Operations

Pacific Gas and Electric Company owns and operates an integrated gas transmission, storage, and distribution system in California. The Utility served approximately 3.8 million gas customers at December 31, 1999. Most of these customers continue to obtain gas supplies from the Utility under regulated tariff rates.

At December 31, 1999, the Utility's system, including the PG&E Expansion (Line 401), consisted of approximately 6,225 miles of transmission pipelines, three gas storage facilities, and approximately 37,487 miles of gas distribution lines. The PG&E Expansion is the Utility's portion of an expansion of the interconnected natural gas transmission systems of the Utility and PG&E Gas Transmission, Northwest Corporation (PG&E GT-Northwest) which extends from the Canadian border into California (Pipeline Expansion). Including the portion owned by PG&E GT-Northwest (PG&E GT-NW Expansion), the 840-mile combined Pipeline Expansion provides an additional 148 million cubic feet per day (MMcf/d) of firm capacity to the Pacific Northwest and an additional 851 MMcf/d of capacity to Northern and Southern California. The Gas Accord resolved various issues concerning the PG&E Expansion and also established certain rules for ratemaking and terms of service applicable to the PG&E Expansion.

The Utility's peak day send-out of gas on its integrated system in California during the year ended December 31, 1999, was 3,503 million cubic feet (MMcf). The total volume of gas throughput during 1999 was approximately 840,000 MMcf, of which 309,000 MMcf was sold to direct end-use or resale customers, 47,000 MMcf was used by the Utility primarily for its fossil-fueled electric generating plants, and 484,000 MMcf was transported as customer-owned gas.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and gas utilities as a result of a CPUC order. A comprehensive biennial report is prepared in even-numbered years with a supplemental report in intervening odd-numbered years updating recorded data for the previous year.

The 1998 California Gas Report updates the Utility's annual gas requirements forecast (excluding bypass volumes) for the years 1999 through 2015, forecasting average annual growth in gas throughput served by the Utility of approximately 1.5%. The 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 utility electric generation, fuel switching, and new technology. In addition, some large customers, mostly in the industrial and enhanced oil recovery sectors, may have the ability to use unregulated private pipelines or interstate pipelines, bypassing the Utility's system entirely.

Gas Operating Statistics

The following table shows Pacific Gas and Electric Company's operating statistics (excluding subsidiaries) for gas, including the classification of sales and revenues by type of service.

	Years Ended December 31,				
	1999	1998	1997	1996	1995
Customers (average for the year):					
Residential	3,593,355	3,536,089	3,491,963	3,455,086	3,417,556
Commercial	203,342	200,620	198,453	198,071	197,939
Industrial	1,625	1,610	1,650	1,500	1,500
Other gas utilities	4	5	3	2	2
Total	3,798,326	3,738,324	3,692,069	3,654,659	3,616,997
Gas supply--thousand cubic feet (Mcf) (in thousands):					
Purchased from suppliers in:					
Canada	230,808	298,125	280,084	253,209	261,800
California	18,956	17,724	10,655	28,130	31,158
Other states	107,226	122,342	131,074	110,604	117,538
Total purchased	356,990	438,191	421,813	391,943	410,496
Net (to storage) from storage	(980)	(14,468)	14,160	6,871	(10,921)
Total	356,010	423,723	435,973	398,814	399,575
Pacific Gas and Electric Company use, losses, etc.(1)	47,152	129,305	173,789	134,375	129,671
Net gas for sales	308,858	294,418	262,184	264,439	269,904
Bundled gas sales and transportation service--Mcf (in thousands):					
Residential	233,482	223,706	191,327	190,246	191,724
Commercial	70,093	66,082	60,803	62,178	64,135
Industrial	5,255	4,616	10,054	12,015	14,045
Other gas utilities	28	14	0	0	0
Total	308,858	294,418	262,184	264,439	269,904
Transportation service only--Mcf (in thousands):					
Vintage system (Substantially all					

Industrial)(2)........	447,867	319,099	218,660	189,695	143,921
PG&E Expansion (Line 401)..................	36,351	77,773	233,269	237,776	240,506
Total..............	484,218	396,872	451,929	427,471	384,427
Revenues (in thousands):					
Bundled gas sales and transportation service:					
Residential..........	$1,542,705	$1,414,313	$1,170,135	$1,109,463	$1,205,223
Commercial...........	448,655	426,299	374,084	362,819	421,397
Industrial...........	24,638	24,634	46,592	42,520	42,106
Other gas utilities..	77	1,072	3,701	510	0
Bundled gas revenues..........	2,016,075	1,866,318	1,594,512	1,515,312	1,668,726
Transportation only revenue:					
Vintage system (Substantially all Industrial).........	267,544	232,038	207,160	180,197	167,325
PG&E Expansion (Line 401)................	19,091	42,194	90,180	85,144	82,904
Transportation service only revenue..........	286,635	274,232	297,340	265,341	250,229
Miscellaneous..........	(47,311)	41,364	50,295	(9,271)	(18,018)
Regulatory balancing accounts..............	(259,648)	(448,351)	(137,787)	57,864	(43,771)
Operating revenues..........	$1,995,751	$1,733,563	$1,804,360	$1,829,246	$1,856,499

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(1) Primarily includes fuel for Pacific Gas and Electric Company's fossil-fueled generating plants.

(2) Does not include on-system transportation volumes transported on the PG&E Expansion of 1,251 MMcf, 34,169 MMcf, 72,958 MMcf, 78,552 MMcf, and 100,207 MMcf for 1999, 1998, 1997, 1996, and 1995, respectively.

	Years Ended December 31,				
	1999	1998	1997	1996	1995
Selected Statistics:					
Average annual residential usage (Mcf)	65	63	55	55	56
Heating temperature--% of normal (1)	108.5	93.0	71.7	75.7	75.3
Average billed bundled gas sales revenues per Mcf:					
Residential	$ 6.61	$ 6.32	$ 6.12	$ 5.83	$ 6.29
Commercial	6.40	6.45	6.15	5.84	6.57
Industrial	4.69	5.36	4.63	3.54	3.00
Average billed transportation only revenue per Mcf:					
Vintage system	0.66	0.66	0.71	0.67	0.69
PG&E Expansion (Line 401)	0.53	0.54	0.39	0.36	0.34
Net plant investment per customer (2)	$1,011	$1,040	$1,031	$1,061	$1,025

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(1) Over 100% indicates colder than normal.

Natural Gas Supplies

The objective of Pacific Gas and Electric Company's Gas Procurement Department is to maintain a balanced supply portfolio that provides supply reliability and contract flexibility, minimizes costs, and fosters competition among the Utility's gas suppliers. To ensure a diverse and competitive mix of natural gas supplies to serve the Utility's customers, the Utility purchases gas directly from producers and marketers in both Canada and the United States.

Under current CPUC regulations, the Utility purchases natural gas from its various suppliers based on economic considerations, consistent with regulatory, contractual, and operational constraints. During the year ended December 31, 1999, approximately 65% of the Utility's total purchases of natural gas consisted of Canadian-sourced gas transported by Canadian pipeline companies and PG&E GT-Northwest and Rocky Mountain-sourced gas transported by PG&E GT-Northwest, approximately 5% was purchased in California, approximately 22% was purchased in the U.S. Southwest and was transported primarily by the El Paso Natural Gas Company and Transwestern Pipeline Company pipelines, and approximately 8% was purchased in the Rocky Mountains and transported by Kern River Gas Transmission Company. California purchases include supplies from various California producers and supplies transported into California by others. The following table shows the total volume and average price of gas in dollars per thousand cubic feet (Mcf) purchased by the Utility from these sources during each of the last five years.

	1999		1998		1997		1996		1995	
	Thousands of Mcf	Avg. Price(1)	Thousands of Mcf	Avg. Price(1)	Thousands of Mcf	Avg. Price(1)	Thousands of Mcf	Avg. Price(1)	Thousands of Mcf	Avg. Price(1)
Canada	230,808	$2.50	298,125	$2.00	280,084	$1.77	253,209	$1.57	261,800	$1.34
California	18,956	2.45	17,724	2.44	10,655	2.12	28,130	1.90	31,158	1.32
Other states										

(substantially all U.S. Southwest).......	107,227	2.42	122,342	2.62	131,074	3.75	110,604	3.72	117,538	2.64
Total/Weighted Average..............	356,991	$2.47	438,191	$2.19	421,813	$2.39	391,943	$2.21	410,496	$1.71

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(1) The average prices for Canadian and U.S. Southwest gas include the commodity gas prices, interstate pipeline demand or reservation charges, transportation charges, and other pipeline assessments, including direct bills allocated over the quantities received at the California border. Beginning March 1, 1998, the average price for gas also includes intrastate pipeline demand and reservation charges. These costs previously were bundled in gas rates.

Gas Regulatory Framework

In August 1997, the CPUC approved the Gas Accord, which restructured Pacific Gas and Electric Company's gas services and its role in the gas market. Among other matters, the Gas Accord separates, or "unbundles," the rates for the Utility's gas transmission services from its distribution services. As a result of the Gas Accord, the Utility's customers may buy gas directly from competing suppliers and purchase transmission-only and distribution-only services from the Utility. Most of the Utility's industrial and larger commercial customers (noncore customers) now purchase their gas from marketers and brokers. Substantially all residential and smaller commercial customers (core customers) buy gas as well as transmission and distribution services from the Utility as a bundled service. Customer rates for gas are updated on a monthly basis to reflect changes in the Utility's gas procurement costs. The Gas Accord established an incentive mechanism (the core procurement incentive mechanism or CPIM) for recovery of the Utility's core gas procurement costs as described below.

The Gas Accord also established gas transmission and storage rates for the period from March 1998 through December 31, 2002. Rates for gas distribution service continue to be set by the CPUC in BCAP proceedings, and are designed to provide the Utility an opportunity to recover its costs of service and include a return on investment. See "Utility Operations--California Ratemaking Mechanisms--Gas Ratemaking--The Biennial Cost Allocation Proceeding (BCAP)."

The CPUC is considering further changes in California's natural gas industry. Additional information concerning gas industry restructuring, and the financial impact of these changes on PG&E Corporation, is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5.

Transportation Commitments

Pacific Gas and Electric Company has gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm capacity on the pipelines. The total demand charges that the Utility will pay each year may change due to changes in tariff rates. The total demand and volumetric transportation charges paid by the Utility under these agreements were approximately $97 million in 1999. This amount includes payments made to PG&E GT-Northwest of approximately $47 million in 1999, which are eliminated in the consolidated financial statements of PG&E Corporation.

As a result of regulatory changes, the Utility no longer procures gas for most of its noncore customers, resulting in a decrease in the Utility's need for firm transportation capacity for its gas purchases. The Utility continues to procure gas for almost all of its core customers and those noncore customers who choose bundled service (core subscription customers). The Utility is continuing its efforts to broker or assign any of its remaining contracted-for but unused interstate and Canadian transportation capacity, including unused capacity held for its core and core-subscription customers.

Under a firm transportation agreement with PG&E GT-Northwest that runs through October 31, 2005, the Utility currently retains capacity of approximately 600 MMcf/d on the PG&E GT-Northwest system to support its core and core-subscription customers. The Utility has been able to broker its unused capacity on PG&E GT-Northwest's system, when not needed for core and core-subscription customers.

In 1992, the Utility entered into a firm transportation agreement with Transwestern Pipeline Company (Transwestern), which expires in 2007, to hold capacity to meet core gas sales demands and electric generation needs. Since the Utility has sold most of its fossil-fueled generating plants in connection with electric industry restructuring and no longer needs natural gas for electric generation, the Utility permanently released 50 MMcf/d of firm capacity under this contract. As a result, the demand charges associated with the entire Transwestern capacity currently approximate $22 million per year. The Utility may recover demand charges through the CPIM and through brokering activities.

Core Procurement Incentive Mechanism

The Utility's core gas procurement costs through 2002 are recoverable in rates under the CPIM, which provides the Utility with a direct financial incentive to procure gas and transportation services at the lowest reasonable costs. Under the CPIM, all Utility procurement costs are compared to an aggregate market-based benchmark. If costs fall within a range (tolerance band) around the benchmark, costs are deemed reasonable and fully recoverable from ratepayers. If procurement costs fall outside the tolerance band, the Utility's ratepayers and shareholders share savings or costs, respectively. Under the Gas Accord and CPIM mechanism, all Utility procurement costs from June 1, 1994 to October 31, 1998, were approved by the CPUC as reasonable. For the period from December 1, 1997 to October 31, 1998, the CPUC, with ORA support, has recognized savings outside of the tolerance band, and for that period has awarded approximately $2 million of the savings to shareholders. In January 2000, the Utility filed a CPIM performance report for the period of November 1, 1998, through October 31, 1999. The report determined that all gas commodity and transportation costs for the period were within the tolerance band, and therefore should be deemed reasonable and recoverable in full from ratepayers.

NATIONAL ENERGY GROUP

PG&E Corporation's National Energy Group has been formed to pursue opportunities created by the gradual deregulation of the energy industry across the nation. The National Energy Group integrates PG&E Corporation's national power generation, gas transmission, and energy trading and services businesses. The National Energy Group contemplates increasing PG&E Corporation's national market presence through a balanced program of acquisition and development of energy assets and businesses, while at the same time undertaking ongoing portfolio management of its assets and businesses. PG&E Corporation's ability to anticipate and capture profitable business opportunities created by deregulation will have a significant impact on PG&E Corporation's future operating results.

Gas Transmission Operations

PG&E Corporation participates in the "midstream" portion of the gas business through PG&E GT. PG&E GT consists of three principal entities: PG&E Gas Transmission, Texas Corporation, PG&E Gas Transmission Teco, Inc., and PG&E GT-Northwest. PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. are referred to collectively as PG&E Gas Transmission, Texas (PG&E GTT). The "midstream" gas business includes (1) gas gathering, processing, storage, and transportation of natural gas and natural gas liquids (NGLs), and (2) the marketing of natural gas and NGLs. PG&E GT's gas transmission facilities are operated through offices in various cities, including Houston and San Antonio, Texas and Portland, Oregon.

PG&E GT competes with, among others, major interstate and intrastate pipeline companies in the transportation of natural gas and NGLs. The principal elements of competition among pipeline companies are rates, terms of service, flexibility, and reliability of service. Natural gas competes with other forms of energy available to PG&E GT's customers and end-users, including electricity, coal, and fuel oils. A significant competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, and governmental regulations, the capability to convert to alternative fuels, and other factors, including weather, affect the demand for natural gas.

PG&E GT also competes with, among others, major integrated energy companies, the marketing affiliates of the major interstate and intrastate pipelines, national and local gas gatherers, brokers, marketers, and distributors for natural gas supplies, in gathering and processing natural gas and in marketing natural gas and NGLs. Competition for natural gas supplies is based on a number of factors, including flexibility in contract terms and conditions, reliability, availability of transportation, and price for the natural gas and NGLs. Competition for sales customers is based upon, among other factors, flexibility of contract terms and conditions, reliability and price of delivered natural gas and NGLs.

PG&E Gas Transmission, Texas

PG&E GTT owns and operates gas gathering, transportation, and processing facilities, and NGL pipelines. The NGL business includes the gathering of natural gas, the extraction of NGLs from natural gas, the fractionation of mixed NGLs into component products (e.g., ethane, propane, butane, and natural gasoline), and the transportation and marketing of NGLs. The Texas operations include approximately 6,700 miles of natural gas pipelines and joint ownership or leasehold interests in approximately 1,300 miles of pipelines, including pipelines from Waha in west Texas to the Katy area near Houston, Texas. These pipeline systems have the capacity to transport more than 3 billion cubic feet (bcf) of gas per day. The Texas assets also include approximately 536 miles of NGL pipelines and nine natural gas processing plants with a combined capacity of approximately 1.6 bcf per day of gas throughput, capable of producing approximately 100,000 barrels per day of NGLs, and a long-term lease of 7.2 bcf of storage capacity. PG&E GTT participates in all areas of the midstream portion of the gas business. PG&E GTT markets gas to gas distribution companies, electric utilities, municipalities, marketers, independent power producers, and end-use customers. It also transports natural gas for these customers, producers, and other pipelines, and markets and transports NGLs to various customers, including end-use customers.

On January 27, 2000, PG&E Corporation's National Energy Group signed a definitive agreement with El Paso Field Services Company providing for the sale to El Paso Field Services Company, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. (collectively PG&E GTT). Closing of the sale, which is expected near the end of the first half of 2000, is subject to approval under the Hart Scott Rodino Act.

Additional information concerning the sale of PG&E GTT is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Note 5 of the "Notes to Consolidated Financial Statements" beginning on page 47 of the 1999 Annual Report to Shareholders.

PG&E GT-Northwest

PG&E GT-Northwest owns and operates gas transmission pipelines and associated facilities which extend over 612 miles from the Canada-U.S. border to the Oregon-California border. PG&E GT-Northwest participates in the midstream portion of the gas business by providing firm and interruptible transportation services to third party shippers on an open access, nondiscriminatory basis. Its customers are principally retail gas distribution utilities, electric utilities that use natural gas to generate electricity, natural gas marketing companies, natural gas producers, and industrial companies. PG&E GT-Northwest's largest customer in 1999 was Pacific Gas and Electric Company, accounting for approximately $49 million, or 23.5% of its transportation revenues.

PG&E GT-Northwest's mainline system is composed of two parallel pipelines with 12 compressor stations totaling approximately 408,660 International Standards Organization (ISO) installed horsepower and ancillary facilities, including metering, regulating facilities, and a communications system. The dual pipeline system consists of approximately 639 miles of 36-inch diameter gas transmission line (612 miles of single 36-inch diameter pipe and 27 miles of 36-inch diameter pipeline looping) and approximately 590 miles of 42-inch diameter pipe. In addition, in 1995, PG&E GT-Northwest constructed two lateral pipeline extensions, adding approximately 84 miles of 12-inch diameter pipe, and 22 miles of 16-inch diameter pipe to serve its customers on those laterals.

PG&E GT-Northwest's total transportation quantities for 1995 through 1999 are set forth in the following table.

Year	Quantities (in thousand decatherms (MDt))
1995	885,186
1996	934,029
1997	969,257
1998	1,003,266
1999	839,778

PG&E GT-Northwest's current rates were set in a rate settlement approved by the FERC in September 1996. In 1998, petitions filed by various parties for rehearing of the FERC order approving the settlement were denied. Three parties have appealed the FERC's denial of these rehearing petitions to the U.S. Court of Appeals for the District of Columbia Circuit. On February 1, 2000, the appellate court denied the petitions for review and reaffirmed the FERC settlement.

Additional information concerning PG&E Corporation's gas transmission operations is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Note 17 of the "Notes to Consolidated Financial Statements" beginning on page 63 of the 1999 Annual Report to Shareholders.

Independent Power Generation

Through PG&E Gen and its affiliates, PG&E Corporation participates in the development, construction, operation, ownership, and management of non-utility electric generating facilities that compete in the United States power generation market. PG&E Gen is headquartered in Bethesda, Maryland.

As of December 31, 1999, PG&E Gen affiliates had ownership interests in 30 operating plants in 10 states. The total generating capacity of these 30 plants is approximately 6,560 MW. Ten of these plants operate as QFs with a combined capacity of 2,128 MW which is sold at fixed prices under long-term power purchase agreements. The remaining plants with a combined capacity of 4,435 MW are operated as merchant power plants that sell their power directly to wholesale customers (including other PG&E Corporation affiliates) at prevailing market prices. PG&E Corporation's combined net equity ownership and leased interest in these plants as of December 31, 1999, represented approximately 5,200 MW. The plants were financed largely with a combination of non-recourse debt and equity or equity commitments from the project sponsors. PG&E Gen, through its affiliate, PG&E Operating Services Company (PG&E OSC), provides contract operations and maintenance services to many of these facilities. PG&E Gen also manages power purchase agreements with an aggregate of 789 MW of capacity. PG&E Gen and its affiliated or managed facilities sold 29,187,905 megawatt-hours (MWh) of electricity in 1999. PG&E Gen also is engaged in the "greenfield" development of new merchant power plants, as discussed below.

PG&E Gen competes with unaffiliated utilities and other independent power producers.

New England Operations

In 1998, PG&E Corporation, through its indirect subsidiary, USGenNE, purchased from the New England Electric System (NEES) a portfolio of electric generating assets with a combined generating capacity of about 4,000 MW. In addition, USGenNE assumed NEES' obligations to purchase power from various independent power producers (IPPs). As of December 31, 1999 these power purchase obligations represented an additional 470 MW of production capacity. NEES is required to make annual support payments to USGenNE through early 2008 to offset the cost of power associated with these above-market contracts. Finally, in connection with the NEES acquisition, USGenNE obtained the right to purchase NEES's nuclear generated electric energy, capacity, and associated products at market prices up to the entire amount available. In December 1999, USGenNE sold these nuclear entitlements.

Three of the four states in which USGenNE operates generation facilities (Massachusetts, Rhode Island, and New Hampshire) were, like California, among the first states in the country to introduce retail competition. As part of electric industry restructuring in these New England states, local utility companies were required to offer standard offer service (SOS) to their retail customers. Retail customers may select alternate suppliers at any time. The SOS is intended to provide customers with a price benefit (the commodity electric price offered to the retail customer under SOS is expected to be less than the market price for the first several years), followed by a price disincentive that is intended to stimulate the retail market. Connecticut also has passed retail competition legislation.

The New England assets are located within the New England Power Pool (NEPOOL). The wholesale electricity market in New England features a bid-based, real-time pricing structure. Traditionally, NEPOOL has operated as a "tight power pool," one in which the utilities within the pool dedicate their generation resources to be centrally dispatched. Dispatch starts with the lowest-cost generation and ends with the highest-cost generation. An independent system operator for the New England states (ISO-NE) provides central dispatch service and operates the power pool as a competitive wholesale marketplace. The duties of the ISO-NE include scheduling the operations of the regional transmission systems and, importantly, operating a power exchange for seven generation products (the "Interchange"). These products are energy, installed (monthly) capacity and operable (hourly) capacity, three types of reserves, and automatic generation control (adjustment of generators to meet the second-to-second changes in electric load).

Additional information concerning the New England electricity market and the Corporation's New England operations is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5.

Portfolio of Operating Generating Plants

The following table sets forth information regarding the operating generating plants in which PG&E Gen affiliates have an ownership or leasehold interest. Except as otherwise noted, PG&E Gen affiliates also manage or operate, or both manage and operate, power plant operations.

Plant	MWs	Fuel	Location	Date Placed in Commercial Service
Bear Swamp Facility(1),(2)				
Pumped Storage 2 Units..........	588	Hydro	Massachusetts	1974
Fife Brook......................	10	Hydro		1974
Brayton Point Station(2)				
Unit Nos. 1, 2, and 3...........	1,130	Coal	Massachusetts	1963, '64, '69
Unit No. 4......................	446	Oil/Gas		1974
Diesel Generators..................	10	Diesel Oil		N/A
Carneys Point......................	260	Coal	New Jersey	1994
Cedar Bay..........................	250	Coal	Florida	1994
Connecticut River(2)				
Hydroelectric 26 Units..........	484	Hydro	New Hampshire/Vermont	1909-1957
Deerfield River(2)				
Hydroelectric 15 Units..........	84	Hydro	Massachusetts/Vermont	1912-1927
Hermiston..........................	474	Natural Gas	Oregon	1996
Indiantown.........................	330	Coal	Florida	1995
Logan..............................	225	Coal	New Jersey	1995
Manchester St. Station(2)				
3 Combined Cycle Units..........	495	Natural Gas	Rhode Island	1995
MASSPOWER..........................	240	Natural Gas	Massachusetts	1993
Northampton........................	110	Waste Coal	Pennsylvania	1995
Pittsfield(1)......................	165	Natural Gas	Massachusetts	1990
Salem Harbor Station(2)				
Unit Nos. 1, 2, and 3...........	314	Coal	Massachusetts	1952, '52, '58
Unit No. 4......................	400	Oil		1972
Scrubgrass.........................	83	Waste Coal	Pennsylvania	1993
Selkirk............................	345	Natural Gas	New York	1992, '94
Total MWs/Operating Plants..	6,443			
PG&E Gen Affiliate Investments:				
Colstrip(3)........................	37	Waste Coal	Montana	1990
Panther Creek(3)...................	83	Waste Coal	Pennsylvania	1992
Total MWs from Investments..	120			
Total MWs in Operation(4)...	6,563			

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(1) Unlike other operating facilities in which PG&E Gen affiliates have

ownership and management interests, the Bear Swamp Facility and the Pittsfield plant are owned by third parties through a single-investor lease arrangement. PG&E Gen maintains full management and operating responsibility for the facilities and is entitled to the output.

(2) Acquired from NEES on September 1, 1998.

(3) PG&E Gen affiliates have an ownership or leasehold interest in these plants, but do not manage power plant operations.

(4) Of the total of 6,563 megawatts in operation, PG&E Gen's net equity ownership and leased percentage interest in the total is 5,225 megawatts.

Generation Development Projects

Nationwide, PG&E Gen's greenfield power plant development activities exceed 10,000 MW in 9 states. The table below lists PG&E Gen's development projects. The Millennium Project in Charlton, Massachusetts (360 MW) and the Lake Road Project in Killingly, Connecticut (792 MW) are under construction. The La Paloma Project in McKittrick, California (1,048 MW) has been approved by PG&E Corporation's Board of Directors and the California Energy Commission. The other development projects listed below are in the early stages of the development process. The completion of these planned projects is subject to many factors, including but not limited to various regulatory and environmental approvals, adequate financing on satisfactory terms, competitive conditions including the expansion and retirement plans of others, market prices for electricity, and future fuel prices.

Plant	MW	Fuel	Location	Estimated start of commercial service
Millennium	360	Natural gas	Massachusetts	4Q 2000
Lake Road	792	Natural gas	Connecticut	2Q 2001
La Paloma	1,048	Natural gas	California	1Q 2002
Madison	12	Wind	New York	3Q 2000
Brayton V	800	Natural gas	Massachusetts	4Q 2002
Athens	1,080	Natural gas	New York	1Q 2002
Covert	1,022	Natural gas	Michigan	3Q 2002
Badger	1,022	Natural gas	Wisconsin	3Q 2002
Liberty	1,048	Natural gas	New Jersey	3Q 2002
Mantua Creek	800	Natural gas	New Jersey	1Q 2002
Otay Mesa	510	Natural gas	California	3Q 2002
Harquahala	1,000	Natural gas	Arizona	3Q 2003
Okeechobee	550	Natural gas	Florida	2Q 2004

Energy Trading

PG&E Energy Trading-Gas Corporation and PG&E Energy Trading-Power, L.P. (also collectively referred to as PG&E ET), headquartered in Houston, Texas, purchase electric power from PG&E Corporation affiliates and the wholesale market and natural gas from producers, marketers, and other parties. PG&E ET then schedules, transports, and resells these commodities, either to third parties or to other PG&E Corporation affiliates (except the Utility). PG&E ET also provides risk management services to PG&E Corporation's other businesses (except the Utiltiy) and to unaffiliated wholesale customers. For more information, see "General--Risk Management Programs" above.

PG&E ET competes with, among others, major integrated energy companies, marketing affiliates of major interstate pipelines, brokers, gas marketers, and gas distributors for natural gas supplies and/or in marketing natural gas. In addition, PG&E ET competes with unaffiliated electric utilities, marketers, and other entities in purchasing and selling electric power and other energy commodities. Competition in the energy marketing business is driven by various factors, including the price of commodities and services delivered along with quality and reliability of services delivered.

Additional information concerning the wholesale operations of PG&E Corporation's affiliates is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Note 17 of the "Notes to Consolidated Financial Statements" beginning on page 63 of the 1999 Annual Report to Shareholders.

Energy Services

PG&E Energy Services (PG&E ES), headquartered in San Francisco, California, provides retail gas and electric commodities nationwide, where permitted under applicable laws, and provides energy-related value-added services, including billing and information management services, energy efficiency and other energy management services, regulatory and rate analysis, and power quality solutions. PG&E ES targets primarily industrial, commercial, and institutional customers, offering comprehensive energy management solutions to reduce their energy costs and improve their productivity. PG&E ES has 20 offices nationwide to support its sales activities. PG&E ES currently competes with other non-utility electric retailers in California for direct access customers. See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring" above.

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E ES, its wholly owned subsidiary, through a sale. The intended disposal has been accounted for as a discontinued operation in PG&E Corporation's 1999 financial statements. While there is no definitive sales agreement, it is expected that the disposition will be completed by June 2000. Additional information concerning PG&E ES is provided in "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, beginning on page 5, and in Notes 5 and 17 of the "Notes to Consolidated Financial Statements" beginning on pages 47 and 63, respectively, of the 1999 Annual Report to Shareholders.

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. This 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.

PG&E Corporation, the Utility, PG&E Gen and its affiliates (including USGenNE), and other PG&E Corporation subsidiaries and affiliates are subject to a number of federal, state, and local laws and regulations designed to protect human health and the environment by imposing stringent controls with regard to planning and construction activities, land use, air and water pollution, and treatment, storage, and disposal of hazardous or toxic materials. These laws and regulations affect future planning and existing operations, including environmental protection and remediation activities. The Utility has undertaken compliance efforts with specific emphasis on its purchase, use, and disposal of hazardous materials, the cleanup or mitigation of historic waste spill and disposal activities, and the upgrading or replacement of the Utility's bulk waste handling and storage facilities. The costs of compliance with environmental laws and regulations generally have been recovered in rates.

Although the Utility has sold most of its fossil-fueled power plants and its geothermal generation facilities in connection with electric industry restructuring, the Utility has retained liability for certain required environmental remediation of pre-closing soil or groundwater contamination for fossil and geothermal generation facilities that have been sold. See "Utility Operations--Electric Utility Operations--California Electric Industry Restructuring--Voluntary Generation Asset Divestiture" above.

Environmental Protection Measures

The estimated expenditures of PG&E Corporation's subsidiaries for environmental protection are subject to periodic review and revision to reflect changing technology and evolving regulatory requirements. It is likely that the stringency of environmental regulations will increase in the future. As a result of the Utility's divestiture of most of its fossil-fueled power plants and its geothermal generation facilities, the Utility's oxides of nitrogen (NOx) emission reduction compliance costs have been reduced significantly.

Air Quality

Pacific Gas and Electric Company's thermal electric generating plants are subject to numerous air pollution control laws, including the California Clean Air Act (CCAA) with respect to emissions. Pursuant to the CCAA and the Federal Clean Air Act, two of the local air districts in which the Utility owns and operates fossil-fueled generating plants have adopted final rules that require a reduction in NOx emissions from the power plants of approximately 90% by

2004 (with numerous interim compliance deadlines).

The Gas Accord authorizes $42 million to be included in rates through 2002, for gas NOx retrofit projects related to natural gas compressor stations on Pacific Gas and Electric Company's Line 300, which delivers gas from the Southwest. Other air districts are considering NOx rules that would apply to the Utility's other natural gas compressor stations in California. Eventually the rules are likely to require NOx reductions of up to 80% at many of these natural gas compressor stations. The Utility currently estimates that the total cost of complying with these various NOx rules will be up to $51 million over three years. Substantially all of these costs will be capital costs.

PG&E Gen's compliance with certain future regulatory requirements limiting the total amount of NOx emissions from its fossil-fueled power plants is expected to be achieved through installation of additional controls, fuel switching, and purchase of NOx allowances. USGenNE has agreed to be bound by a number of state and regional initiatives that will require it to achieve significant reductions of sulfur dioxide (SO\\2\\) and NOx emissions by the time its older fossil-fueled power plants have been in operation for 40 years or by 2010, whichever comes first. It is expected that USGenNE can meet these requirements through utilization of allowances it currently owns, installation of additional controls, or purchase of additional allowances. (SO\\2\\ allowances are emission credits that are traded in a national market under the United States Environmental Protection Agency's (EPA) Acid Rain Program. NOx allowances are emission credits that are traded in a regional market consisting of seven Northeast states known as the Ozone Transport Region.) It is estimated that USGenNE's total cost of complying with these requirements will be up to $4 million through the year 2001.

Water Quality

Pacific Gas and Electric Company's existing power plants, including Diablo Canyon, are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. The Utility's fossil-fueled power plants comply in all material respects with the discharge constituents standards and either comply in all material respects with or are exempt from the thermal standards. A thermal effects study at Diablo Canyon was completed in May 1988, and was reviewed by the Central Coast Regional Water Quality Control Board (Central Coast Board). The Central Coast Board did not make a final decision on the report and requested that the Utility continue its thermal effects monitoring program. In 1995, the Central Coast Board requested that the Utility prepare an updated comprehensive assessment of Diablo Canyon's thermal effects and approved a reduced environmental monitoring program. A comprehensive statistical analysis of Diablo Canyon's thermal effects was submitted to the Central Coast Board in December 1997 and a regulatory assessment was submitted in November 1998. If the Central Coast Board finds that Diablo Canyon's existing thermal limits are not protective of beneficial uses of the marine waters, major modifications (e.g., cooling towers) resulting in additional construction expenditures, or reduced power operation, could be required.

Pursuant to the federal Clean Water Act, the Utility is required to demonstrate that the location, design, construction, and capacity of power plant cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts at its existing water-cooled thermal plants. The Utility has submitted detailed studies of each power plant's intake structure to various governmental agencies. Each plant's existing water intake structure was found to meet the BTA requirements. The Utility currently is completing a new study for Diablo Canyon. The study is scheduled to be submitted to the Central Coast Board for review in 2000. If the Central Coast Board finds that Diablo Canyon's cooling water intake structure does not meet the BTA requirements, additional expenses for construction or mitigation could be required. In addition, the promulgation or modification of statutes, regulations, or water quality control plans at the federal, state, or regional level may impose increasingly stringent cooling water discharge requirements on the Utility's remaining power plants in the future. Costs to comply with renewed permit conditions required to meet any more stringent requirements that might be imposed cannot be estimated at the present time.

In December 1999, the Utility was notified by the purchaser of its former Moss Landing power plant that that it had identified a cleaning procedure used at the plant that released heated water from the intake, and that this procedure is not specified in the plant's National Pollutant Discharge Elimination System (NPDES) permit issued by the Central Coast Board. The purchaser notified the Central Coast Board of its findings and the Central Coast Board requested additional information from the purchaser. The Utility has initiated an investigation of these activities during the time it owned the plant. The Central Coast Board has been notified of the investigation and the results will be presented to the Central Coast Board when the investigation is complete. If the identified procedure was performed during the Utility's ownership and was beyond the scope of the relevant NPDES permits, the Central Coast Board may choose to initiate an enforcement action. If so, the Utility could be subject to significant penalties. Until the investigation is complete and the results discussed with the Central Coast Board, it is not possible to determine whether the Utility will suffer a loss in connection with this matter or to provide a more detailed estimate of such liability.

PG&E Gen's existing power plants, including USGenNE facilities, are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. Three of the fossil-fueled plants owned and operated by USGenNE are operating in compliance with NPDES permits that have expired. As to the facilities for which the NPDES permit has expired, new permit applications are pending, and it is anticipated that all three facilities will be able to continue to operate under existing terms and conditions until new permits are issued. USGenNE has submitted a permit renewal application and is negotiating with EPA on ongoing studies and permit conditions. It is estimated that USGenNE's cost to comply with these conditions could be as much as $5 million through the year 2001.

Hazardous Waste Compliance and Remediation

PG&E Corporation subsidiaries assess, on an ongoing basis, measures that may need to be taken to comply with laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility has a comprehensive program to comply with many hazardous waste storage, handling, and disposal requirements promulgated by the EPA under the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), along with other state hazardous waste laws and other environmental requirements.

One part of this program is aimed at assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation, manufactured gas plants produced lampblack and tar residues, byproducts of a process that Pacific Gas and Electric Company, its predecessor companies, and other utilities used as early as the 1850s to manufacture gas from coal and oil. As natural gas became widely available (beginning about 1930), the Utility's manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility has identified and reported to federal and California environmental agencies 96 manufactured gas plant sites that operated in the Utility's service territory. The Utility owns all or a portion of 29 of these manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at sites that the Utility owns. It is estimated that the Utility's program may result in expenditures of approximately $5 million in 2000. The full long-term costs of the program cannot be determined accurately until a closer study of each site has been completed. It is expected that expenses will increase as remedial actions related to these sites are approved by regulatory agencies or if the Utility is found to be responsible for cleanup at sites it currently does not own.

In addition to the manufactured gas plant sites, the Utility may be required to take remedial action at certain other disposal sites if they are determined to present a significant threat to human health and the environment because of an actual or potential release of hazardous substances. The Utility has been designated as a potentially responsible party (PRP) under CERCLA (the federal Superfund law) with respect to the PRC Patterson site in Patterson, California, and the Industrial Waste Processing site near Fresno, California. With respect to the Casmalia site near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires these generators to perform certain site investigation and mitigation measures, and provides a release from liability for certain other site cleanup obligations. Although the Utility has not been formally designated a PRP with respect to the Geothermal Incorporated site in Lake County, California, the Central Valley Regional Water Quality Control Board and the California Attorney General's office have directed the Utility and other parties to initiate measures with respect to the study and remediation of that site.

In addition, Pacific Gas and Electric Company 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 the Utility no longer owns or never owned.

The cost of hazardous substance remediation ultimately undertaken by Pacific Gas and Electric Company is difficult to estimate. It is reasonably possible that a change in the estimate 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. At December 31, 1999, the Utility expects to spend $300 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants, where such costs are probable and quantifiable. (Although the Utility has sold most of its fossil-fueled power plants, the Utility has retained pre-closing environmental liability with respect to these plants.) The Utility had an accrued liability of $271 million at December 31, 1999, representing the discounted value of these costs. Environmental remediation at identified sites may be as much as $486 million if, among other things, other PRPs are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated at sites for which the Utility is responsible. The Utility estimated the upper limit of the range of costs using assumptions least favorable to the Utility based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for cleanup costs at additional sites or identifiable possible outcomes change.

PG&E Gen acquired the onsite environmental liability associated with USGenNE's acquisition of electric generating facilities from NEES, but did not acquire any offsite liability associated with the past disposal practices at the acquired facilities. PG&E Gen has obtained pollution liability and environmental remediation insurance coverage to limit the financial risk associated with the onsite pollution liability at all of its facilities.

Potential Recovery of Hazardous Waste Compliance and Remediation Costs

In 1994, the CPUC established a ratemaking mechanism for hazardous waste remediation costs (HWRC). That mechanism assigns 90% of the includable hazardous substance cleanup costs to utility ratepayers and 10% to utility shareholders, without a reasonableness review of such costs or of underlying activities. Under the HWRC mechanism, 70% of the ratepayer portion of Pacific Gas and Electric Company's cleanup costs is attributed to its gas department and 30% is attributed to its electric department. Insurance recoveries are assigned 70% to shareholders and 30% to ratepayers until both are reimbursed for the costs of pursuing insurance recoveries. The balance of insurance recoveries are allocated 90% to shareholders and 10% to ratepayers until shareholders are reimbursed for their 10% share of cleanup costs. Any unallocated funds remaining are held for five years and then distributed 60% to ratepayers and 40% to shareholders over the next five years. The Utility can seek to recover hazardous substance cleanup costs under the HWRC in the rate proceeding it deems most appropriate. In connection with electric industry restructuring, the HWRC mechanism may no longer be used to recover electric generation-related cleanup costs for contamination caused by events occurring after January 1, 1998.

For each divested generation facility where the Utility retained environmental remediation liabilities, the plant's decommissioning cost estimate was adjusted by the Utility's estimated forecast of environmental remediation costs. (The buyers assumed the non-environmental decommissioning liability for these plants.) The CPUC ordered that excess recoveries of environmental and non-environmental decommissioning accruals related to the divested plants be used to offset other transition costs. As of December 31, 1999, the Utility has recovered from ratepayers approximately $114 million for environmental decommissioning accrual related to the divested plants. This amount will earn interest at 3% per year that will be used to meet the future environmental remediation costs for the divested plants. The net decommissioning accruals recovered from ratepayers attributable to the non-environmental liability for the divested plants was approximately $53 million. Because the Utility no longer has this non-environmental decommissioning liability, it has used this excess recovery amount to reduce other transition costs.

Of the $271 million accrued liability, discussed above, the Utility has recovered $148 million through rates, including $34 million through depreciation, and expects to recover $95 million in future rates. Additionally, the Utility is mitigating its costs by seeking recovery of its costs from insurance carriers and from other third parties as appropriate.

In 1992, Pacific Gas and Electric Company filed a complaint in San Francisco County Superior Court against more than 100 of its domestic and foreign insurers, seeking damages and declaratory relief for remediation and other costs associated with hazardous waste mitigation. The Utility previously had notified its insurance carriers that it seeks coverage under its comprehensive general liability policies to recover costs incurred at certain specified sites. In general, the Utility's carriers neither admitted nor denied coverage, but requested additional information from the Utility. Although the Utility has received some amounts in settlements with certain of its insurers (approximately $71 million through December 31, 1999), the ultimate amount of recovery from insurance coverage, either in the aggregate or with respect to a particular site, cannot be quantified at this time.

Compressor Station Litigation

Several cases have been brought against Pacific Gas and Electric Company seeking damages from alleged chromium contamination at the Utility's Hinkley, Topock, and Kettleman Compressor Stations. See Item 3, "Legal Proceedings--Compressor Station Chromium Litigation" below, for a description of the pending litigation.

Electric and Magnetic Fields

In January 1991, the CPUC opened an investigation into potential interim policy actions to address increasing public concern, especially with respect to schools, regarding potential health risks that may be associated with electric and magnetic fields (EMF) from utility facilities. In its order instituting the investigation, the CPUC acknowledged that the scientific community has not reached consensus on the nature of any health impacts from contact with EMF, but went on to state that a body of evidence has been compiled that raises the question of whether adverse health impacts might exist.

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 EMF from new and upgraded utility facilities. California energy utilities are required to fund a $1.5 million EMF education program and a $5.6 million EMF research program managed by the California Department of Health Services. It is expected that the CPUC and the California Department of Health Services will complete its EMF research program by December 2001.

As part of its effort to educate the public about EMF, Pacific Gas and Electric Company provides interested customers with information regarding the EMF exposure issue. The Utility also provides a free field measurement service to inform customers about EMF levels at different locations in and around their residences or commercial buildings.

The Utility currently is not involved in third party litigation concerning EMF. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMF from power lines. The Court expressly limited its holding to property value issues, leaving open the question as to whether lawsuits for alleged personal injury resulting from exposure to EMF are similarly barred. The Utility was a defendant in civil litigation in which plaintiffs alleged personal injuries resulting from exposure to EMF. In January 1998, the appeals court in this matter held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMF and barred plaintiffs' personal injury claims. Plaintiffs filed an appeal of this decision with the California Supreme Court. The California Supreme Court declined to hear the case.

If the scientific community reaches a consensus that EMF presents a health hazard and further determines that the impact of utility-related EMF exposures can be isolated from other exposures, the Utility may be required to take mitigation measures at its facilities. The costs of such mitigation measures cannot be estimated with any certainty at this time. However, such costs could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines ultimately is required.

Low Emission Vehicle Programs

In December 1995, the CPUC issued its decision in the Low Emission Vehicle (LEV) proceeding, which approved approximately $42 million in funding for Pacific Gas and Electric Company's LEV program for the six-year period beginning in 1996. The CPUC's decision on electric industry restructuring found that the costs of utility LEV programs should continue to be collected by the utility for the duration of the six-year period. The Utility continues to run its LEV program as funded.

ITEM 2. Properties.

Information concerning Pacific Gas and Electric Company's electric generation units, electric and gas transmission facilities, and electric and gas distribution facilities is included in response to Item 1. All of the Utility's real properties and substantially all of the Utility's personal properties are subject to the lien of an indenture that provides security to the holders of the Utility's First and Refunding Mortgage Bonds.

Information concerning properties and facilities owned by other PG&E Corporation subsidiaries is included in the discussion under the heading of this report entitled "National Energy Group."

ITEM 3. Legal Proceedings.

See Item 1, Business, for other proceedings pending before governmental and administrative bodies. In addition to the following legal proceedings, PG&E Corporation and Pacific Gas and Electric Company are subject to routine litigation incidental to their business.

Compressor Station Chromium Litigation

Pacific Gas and Electric Company is currently a defendant in three civil actions pending in California courts. These cases are (1) Aguayo v. Pacific Gas and Electric Company, filed March 15, 1995, in Los Angeles County Superior Court, (2) Aguilar v. Pacific Gas and Electric Company, filed October 4, 1996, in Los Angeles County Superior Court, and (3) Acosta, et al. v. Betz Laboratories, Inc., Pacific Gas and Electric Company, et al., filed November 27, 1996, in Los Angeles County Superior Court. These cases are collectively referred to as the "Aguayo Litigation." There are approximately 900 plaintiffs in the Aguayo Litigation.

Each of the complaints in the Aguayo Litigation alleges personal injuries and seeks compensatory and punitive damages in an unspecified amount arising out of alleged exposure to chromium contamination in the vicinity of the Utility's gas compressor stations at Kettleman, Hinkley, and Topock, California. The plaintiffs in the Aguayo Litigation include current and former Utility employees, relatives of current and former employees, residents in the vicinity of the compressor stations, and persons who visited the gas compressor stations. The plaintiffs also include spouses or children of these plaintiffs who claim loss of consortium or wrongful death.

All discovery and discovery motion practice in the Aguayo Litigation have been referred by the judge to a discovery referee. The discovery referee has set the procedures for selecting 18 trial test plaintiffs and two alternates in the Aguayo Litigation. Ten of these trial test plaintiffs were selected by plaintiffs, seven trial test plaintiffs were selected by defendants, and one trial test plaintiff and two alternates were selected at random. The trial date has been set for November 17, 2000 in Los Angeles Superior Court.

The Utility is responding to the complaints and asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations or exclusivity of workers' compensation laws, and factual defenses including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged. At this stage of the proceedings, there is substantial uncertainty concerning the claims alleged. The Utility is attempting to gather information concerning the alleged type and duration of exposure, the nature of injuries alleged by individual plaintiffs, and the additional facts necessary to support its legal defenses, in order to better evaluate and defend this litigation.

PG&E Corporation believes that the ultimate outcome of this matter will not have a material adverse impact on its or Pacific Gas and Electric Company's financial position or results of operations.

Texas Franchise Fee Litigation

On July 31, 1997, PG&E Corporation acquired Valero Energy Corporation (Valero), now known as PG&E Gas Transmission, Texas Corporation. PG&E Gas Transmission, Texas Corporation and its affiliates (PG&E GTT) succeeded to the cases described below, which were pending at the time of the acquisition against Valero and its affiliates. A lawsuit was also pending at such time that had been filed by the City of Pharr, but no PG&E GTT entity has been served in this case. These cases are collectively referred to as the "Texas Franchise Fees Litigation." These actions were brought by various cities in Texas arising out of several Texas statutes and city ordinances involving the following: (a) what rights, if any, Texas cities may have to require companies engaged in the gathering, production, distribution, transmission, and/or sale of natural gas to obtain consent from, and pay fees to, the cities within which such activities are being conducted, (b) what form any such consent, if required, must take, (c) what constitutes "use" of city property, and (d) what types of charges, if any, a Texas city properly can assess against gas pipeline and marketing companies for use of that city's property.

There were seven cases pending against Valero entities at the time of the acquisition: (1) City of Edinburg v. Rio Grande Valley Gas Co. (RGVG), Valero Energy Corporation (now known as PG&E GTT), Valero Transmission Company (now known as PG&E Texas Pipeline Company), Valero Natural Gas Company (now known as PG&E Texas Natural Gas Company), Reata Industrial Gas Company a/k/a Valero Gas Marketing Company (now known as PG&E Energy Trading Holdings Corporation), Valero Transmission, L.P. (now known as PG&E Texas Pipeline, L.P.), and Reata Industrial Gas, L.P. (now known as PG&E Reata Energy, L.P.), Southern Union Company and its unincorporated division, Southern Union Gas Co. (Southern Union), and Mercado Gas Services, Inc., filed August 31, 1995, in the 92nd State District Court, Hidalgo County, Texas, (2) Cities of San Benito, Primera, and Port Isabel v. RGVG, Valero Energy Corporation (now known as PG&E GTT), Southern Union, et al., filed December 31, 1996, in the 107th State District Court, Cameron County, Texas, (3) City of Mercedes v. Reata Industrial Gas, L.P. (now known as PG&E Reata Energy, L.P.), and Valero Gas Marketing Company (now known as PG&E Energy Trading Holdings Corporation), filed April 16, 1997, in the 92nd State District Court in Hidalgo County, Texas, (4) Cities of Alton and Donna v. RGVG, Valero Energy Corporation (now known as PG&E Gas Transmission, Texas Corporation), Valero Transmission Company (now known as PG&E Texas Pipeline Company), Valero Natural Gas Company (now known as PG&E Texas Natural Gas Company), Reata Industrial Gas Company (now known as PG&E Energy Trading Holdings Corporation), Valero Transmission, L.P. (now known as PG&E Texas Pipeline, L.P.), and Reata Industrial Gas, L.P. (now known as PG&E Reata Energy, L.P.), Southern Union Gas Co., and Mercado Gas Services, Inc., filed July 18, 1996, in the 92nd State District Court, Hidalgo County, Texas, (5) City of La Joya v. RGVG, Valero Energy Corporation (now known as PG&E GTT), Southern Union Company, et al., filed December 27, 1996, in the 92nd State District Court, Hidalgo County, Texas, (6) Cities of San Juan, La Villa, Penitas, Edcouch, and Palmview v. RGVG, Valero Energy Corporation (now known as PG&E Gas Transmission, Texas Corporation), Southern Union Company, et al., filed December 27, 1996, in the 93rd State District Court, Hidalgo County, Texas, and (7) City of Weslaco v. Valero Natural Gas Company (now known as PG&E Texas Natural Gas Company), Valero Gas Marketing Co. (now known as PG&E Energy Trading Holdings Corporation), and Reata Industrial Gas, L.P. (now known as PG&E Reata Energy L.P.) filed April 17, 1997, in the 92nd State District Court, Hidalgo County, Texas. The lawsuits involving the City of La Joya (item number 5 above) and the Cities of San Juan, La Villa, Penitas, Edcouch, and Palmview (item number 6 above) were voluntarily dismissed on July 13, 1999, and February 23, 2000, respectively.

However, all of these cities are class members in the San Benito class action (item number 5 above) as are the Cities of Alton and Donna.

The trial in the City of Edinburg case began on June 15, 1998. On August 14, 1998, a jury returned a verdict in favor of the City of Edinburg, and awarded damages in the approximate aggregate amount of $9.8 million, plus attorneys' fees of approximately $3.5 million, against PG&E GTT, Southern Union and various affiliates of PG&E GTT and Southern Union. The jury refused to award punitive damages against the PG&E GTT defendants. On December 1, 1998, based on the jury verdict, the court entered a judgment in the City's favor, and awarded damages of $5.3 million, attorneys' fees of up to $3.5 million (to the extent that the City is successful on appeal), prejudgment interest of $1.6 million, and post-judgment interest at the rate of 10% per year, compounded annually, from December 1, 1998. The court found that various PG&E GTT and Southern

Union defendants were jointly and severally liable for $3.3 million of the damages, prejudgment interest in the amount of $1.1 million, and all the attorneys' fees. Certain PG&E GTT subsidiaries were found solely liable for $1.4 million of the damages and prejudgment interest of $440,000. The court did not clearly indicate the extent to which the PG&E GTT defendants could be found liable for the remaining damages. The judgment also decreed that (1) certain pipelines owned by PG&E Texas Pipeline, L.P. (formerly known as Valero Transmission, L.P.) encroached on the City's property without the City's consent and (2) based on certain jury findings, PG&E GTT was vicariously liable for certain conduct of the local distribution company, RGVG, from October 1, 1985, to September 30, 1993 (the date Valero, PG&E GTT's predecessor, sold RGVG to Southern Union). The PG&E GTT defendants are appealing the judgment.

On November 4, 1997, the lawsuit filed in Cameron County, Texas, by the cities of San Benito, Primera, and Port Isabel was amended to name as defendants PG&E GTT and all of its subsidiaries (excluding its Canadian gas trading and power trading subsidiaries), PG&E Gas Transmission Teco, Inc. and its subsidiaries, and PG&E Energy Trading Corporation (now known as PG&E Energy Trading--Gas Corporation) (collectively these defendants are referred to as the "PG&E Corporation Texas defendants"). In November 1997, the court ordered a state-wide class certified and granted plaintiffs' request to dismiss RGVG and the Southern Union defendants. In connection with the certification of a class in this case, the court ordered notice to be sent to all potential class members and setting an opt-out deadline of December 31, 1997. Notices were mailed to approximately 159 Texas cities. Fewer than 20 cities opted out by the deadline. Some of the cities opting out include Austin, Brownsville, Houston, and San Antonio. The city of Los Indios has been severed from the class and its claims separately docketed in Cameron County, Texas. On November 22, 1999, the court signed an order dismissing from the class 42 cities because it determined there was no pipeline presence and no past or present sales activity in such cities, leaving 106 cities in the class. The parties are negotiating the terms of a final settlement agreement. The settlement proposal contemplates, among other things, that the PG&E Corporation Texas defendants would pay a total of not more than $12.2 million to the settling class cities, inclusive of attorney fees and expenses, which amount may be reduced by amounts attributable to certain opt-out cities. The defendants retain the right to reject the settlement if the settlement proposal is not approved by certain key cities and by 80% of the overall plaintiff class. Although a significant number of the 106 cities in the plaintiff class already have either approved the settlement by enacting the consent ordinance or have adopted resolutions to pass the ordinance, certain key cities have not yet approved the settlement. The settlement is also subject to final court approval. On January 27, 2000, the court approved the settlement proposal and established a 14-day period for the cities to decide whether to accept the negotiated settlement terms or opt out of the settlement. The court also stated that if the City of Corpus Christi does not accept the settlement proposal, it will be placed in a single city sub-class and its claims will not be finalized as part of the settlement approval. Corpus Christi has the right to opt out of this subclass. Although the 14-day period expired on February 11, 2000, certain cities have requested and received additional time to decide whether to opt out.

In July 1996, the lawsuits originally filed by the cities of Alton and Donna as intervening actions in the City of Edinburg case were severed from the Edinburg lawsuit. The claims asserted by the cities of Alton and Donna are substantially similar to the San Benito litigation claims, except that no class claims are asserted. Damages are not quantified. Defendants' motion to transfer venue of both cases to Bexar County, Texas, is currently pending. The Cities of Alton and Donna are also members of the San Benito class, and will be required to dismiss their claims against PG&E GTT in this separate lawsuit if they agree to accept the settlement of the San Benito class action.

On September 4, 1997, the City of Mercedes amended its petition to include class action claims and requested to be named as class representative for a statewide class consisting of all Texas municipal corporations, municipalities, towns, and villages, excluding the cities of Edinburg and Weslaco (both of which have filed separate actions), in which any of the defendants have sold or supplied gas, or used public rights-of-way to transport gas. The City of Mercedes has requested a damage award, but has not specified an amount. On November 26, 1997, defendants' motion to recuse the presiding judge was granted. Plaintiffs' request for class certification is still pending.

The causes of action alleged in the case brought by the City of Weslaco are identical to those alleged in the City of Mercedes case, except that no class claims are asserted. Damages are not quantified. A motion similar to the motion filed in Mercedes, seeking to recuse the judge of the 92nd State District Court, was filed but not ruled upon. On May 12, 1999, this case was transferred to the 370th State District Court of Hidalgo County, Texas. Defendants' motion to transfer venue to Bexar County, Texas, is currently pending.

In addition to the cases described above, during May 1996, a petition in intervention was filed in the Edinburg case by the City of Pharr. On June 24, 1996, the court severed Pharr from the Edinburg case, certified the severed case as a class action against Southern Union Company and RGVG, and named Pharr as class representative for a class consisting of those Texas cities, excluding Edinburg and McAllen, that have or had natural gas franchise agreements with RGVG or Southern Union. The Pharr class was certified as to two claims: breach of contract and declaratory relief dealing with the rights, status, and legal relationship between plaintiff, the class members, and the local distribution company regarding payment of franchise fees and use of granted easements. Plaintiffs' original petition also sought injunctive relief, but the class order does not include injunctive relief. Plaintiffs seek actual damages, exemplary damages, attorneys' fees, costs, and pre- and post-judgment interest, but have not specified any amounts. On January 26, 1998, the court added the Cities of Mercedes and Weslaco as class representatives. None of the PG&E Corporation Texas entities have ever been served in the Pharr litigation. On December 30, 1997, in affirming the Pharr class certification, the appellate court specifically found that the PG&E GTT entities were not parties to the Pharr class action. However, the same 29 PG&E Corporation Texas entities that are class defendants in the San Benito litigation have subsequently been named and served as defendants in two ancillary suits brought during 1998 by the Pharr class plaintiffs. These ancillary suits seek only injunctive relief, for the stated purpose of "protecting" the Pharr class from alleged interference by the San Benito class.

PG&E Corporation believes that the ultimate outcome of this matter will not have a material adverse impact on its financial position or results of operations. As discussed above under "Item 1--National Energy Group-- Gas Transmission Operations," in January 2000, PG&E Corporation's National Energy Group signed a definitive agreement to sell the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc., the National Energy Group subsidiaries which conduct gas transmission operations in Texas. The buyer will assume all liabilities associated with the cases described above.

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

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of PG&E Corporation are as follows:

Name	Age at December 31, 1999	Position
R. D. Glynn, Jr.	57	Chairman of the Board, Chief Executive Officer, and President
T. G. Boren.............	50	Executive Vice President; President and Chief Executive Officer, PG&E National Energy Group, Inc.
P. A. Darbee............	47	Senior Vice President, Chief Financial Officer, and Treasurer
S. W. Gebhardt..........	48	Senior Vice President; President and Chief Executive Officer, PG&E Energy Services Corporation
T. W. High..............	52	Senior Vice President, Administration and External Relations
P. C. Iribe.............	49	Senior Vice President; President and Chief Operating Officer, PG&E Generating Company
T. B. King..............	38	Senior Vice President; President and Chief Operating Officer, PG&E Gas Transmission Corporation
L. E. Maddox............	44	Senior Vice President; President and Chief Executive Officer, PG&E Energy Trading Corporation
G. R. Smith.............	51	Senior Vice President; President and Chief Executive Officer, Pacific Gas and Electric Company
G. B. Stanley...........	53	Senior Vice President, Human Resources
B. R. Worthington.......	50	Senior Vice President and General Counsel

All officers of PG&E Corporation serve at the pleasure of the Board of Directors. During the past five years, 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
R. D. Glynn, Jr.	Chairman of the Board, Chief Executive Officer, and President	January 1, 1998, to present
	Chairman of the Board of Directors, Pacific Gas and Electric Company	January 1, 1998, to present

	President and Chief Executive Officer	June 1, 1997, to present
	President and Chief Operating Officer	December 18, 1996, to May 31, 1997
	President and Chief Operating Officer, Pacific Gas and Electric Company	June 1, 1995, to May 31, 1997
	Executive Vice President, Pacific Gas and Electric Company	July 1, 1994, to May 31, 1995
T. G. Boren............	Executive Vice President	August 1, 1999, to present
	President and Chief Executive Officer, PG&E National Energy Group, Inc.	August 1, 1999, to present
	President and Chief Executive Officer, Southern Energy, Inc.	February 18, 1992, to July 31, 1999
	Executive Vice President, Southern Company	June 1, 1999, to July 31, 1999
	Senior Vice President, Southern Company	February 16, 1998, to May 31, 1999
	Vice President, Southern Company	July 17, 1995, to February 15, 1998
P. A. Darbee...........	Senior Vice President, Chief Financial Officer, and Treasurer	September 20, 1999, to present
	Vice President and Chief Financial Officer, Advance Fibre Communications, Inc.	June 30, 1997, to September 19, 1999
	Vice President, Chief Financial Officer, and Controller, Pacific Bell	January 10, 1994, to June 30, 1997
S. W. Gebhardt.........	Senior Vice President	April 1, 1997, to present
	President and Chief Executive Officer, PG&E Energy Services Corporation	April 1, 1997, to present
	Executive Vice President, PennUnion Energy Services	April 1, 1996, to March 28, 1997
	Vice President, Enron Capital & Trade Resources	January 1, 1993, to December 31, 1995

Name	Position	Period Held Office
T. W. High.............	Senior Vice President, Administration and External Relations	June 1, 1997, to present
	Senior Vice President, Corporate Services, Pacific Gas and Electric Company	June 1, 1995, to May 31, 1997
	Vice President and Assistant to the Chief Executive Officer, Pacific Gas and Electric Company	July 1, 1994, to May 31, 1995
P. C. Iribe............	Senior Vice President	January 1, 1999, to present
	President and Chief Operating Officer, PG&E Generating Company (formerly known as U.S. Generating Company)	November 1, 1998, to present
	Executive Vice President and Chief Operating Officer, U.S. Generating Company	September 1, 1997, to October 31, 1998
	Executive Vice President, Marketing, Development, and Asset Management, U.S. Generating Company	May 17, 1994, to September 1, 1997
T. B. King.............	Senior Vice President	January 1, 1999, to present
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1998, to present
	President and Chief Operating Officer, Kinder Morgan Energy Partners, L.P.	February 14, 1997, to November 22, 1998
	Vice President, Commercial Operations--Midwest Region, Enron Liquid Services Corporation	July 1, 1995, to February 14, 1997
	Vice President, Gathering Services, Northern Natural Gas Company and Transwestern Pipeline Company	July 1994, to July 1, 1995
L. E. Maddox...........	Senior Vice President	June 1, 1997, to present
	President and Chief Executive Officer, PG&E Energy Trading Corporation	May 12, 1997, to present
	President, PennUnion Energys Services, L.L.C.	May 1995 to May 1997
	President, Brooklyn Interstate Natural Gas Corp.	January 1993 to May 1995
G. R. Smith............	Senior Vice President (Please refer to description of business experience for executive	January 1, 1999, to present

	officers of Pacific Gas and Electric Company below.)	
G. B. Stanley...........	Senior Vice President, Human Resources	January 1, 1998, to present
	Vice President, Human Resources	June 1, 1997, to December 31, 1997
	Vice President, Human Resources, Pacific Gas and Electric Company	July 1, 1996, to May 31, 1997
	Self-employed (human resources consultant)	January 1995, to June 1996
B. R. Worthington.......	Senior Vice President and General Counsel	June 1, 1997, to present
	General Counsel	December 18, 1996, to May 31, 1997
	Senior Vice President and General Counsel, Pacific Gas and Electric Company	June 1, 1995, to June 30, 1997
	Vice President and General Counsel, Pacific Gas and Electric Company	December 21, 1994, to May 31, 1995

"Executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, of Pacific Gas and Electric Company are as follows:

Name	Age at December 31, 1999	Position
G. R. Smith.............	51	President and Chief Executive Officer
K. M. Harvey............	41	Senior Vice President, Chief Financial Officer, Controller, and Treasurer
R. J. Peters............	45	Senior Vice President and General Counsel
J. K. Randolph..........	55	Senior Vice President and General Manager, Transmission, Distribution and Customer Service Business Unit
D. D. Richard, Jr.......	49	Senior Vice President, Governmental and Regulatory Relations
G. M. Rueger............	49	Senior Vice President and General Manager, Nuclear Power Generation Business Unit

All officers of Pacific Gas and Electric Company serve at the pleasure of the Board of Directors. During the past five years, the executive officers of Pacific Gas and Electric Company 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
G. R. Smith.............	President and Chief Executive Officer	June 1, 1997, to present
	Chief Financial Officer, PG&E Corporation	December 18, 1996, to May 31, 1997
	Senior Vice President and Chief Financial Officer	June 1, 1995, to May 31, 1997
	Vice President and Chief Financial Officer	November 1, 1991, to May 31, 1995
K. M. Harvey............	Senior Vice President, Chief Financial Officer, Controller, and Treasurer	January 1, 2000, to present
	Senior Vice President, Chief Financial Officer, and Treasurer	July 1, 1997, to December 31, 1999
	Vice President and Treasurer	June 1, 1995, to June 30, 1997
	Treasurer	August 1, 1993, to May 31, 1995
R. J. Peters............	Senior Vice President and General Counsel	January 1, 1999, to present
	Vice President and General Counsel	July 1, 1997, to December 31, 1998
	Chief Counsel, Regulatory	January 1, 1993, to June 30, 1997

J. K. Randolph..........	Senior Vice President and General Manager, Transmission, Distribution and Customer Service Business Unit	July 1, 1997, to present
	Vice President and General Manager, Power Generation, Business Unit	January 1, 1997, to June 30, 1997
	Vice President, Power Generation	November 1, 1991, to December 31, 1996
D. D. Richard, Jr.......	Senior Vice President, Governmental and Regulatory Relations	July 1, 1997, to present
	Vice President, Governmental Relations, PG&E Corporation	July 1, 1997, to present
	Vice President, Governmental Relations	January 1, 1997, to June 30, 1997
	Executive Vice President and Principal, Morse, Richard, Weisenmiller & Assoc., Inc. (energy, project finance, and environmental consulting)	January 1993, to December 1996
G. M. Rueger............	Senior Vice President and General Manager, Nuclear Power Generation Business Unit	November 1, 1991, to present

PART II

ITEM 5. Market for the Registrant's Common Equity and Related Stockholder Matters.

Information responding to part of Item 5, for each of PG&E Corporation and Pacific Gas and Electric Company, is set forth on page 67 under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 1999 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of February 22, 2000, there were 149,708 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York, Pacific, and Swiss stock exchanges. The discussion of dividends with respect to PG&E Corporation's common stock is hereby incorporated by reference from "Management's Discussion and Analysis--Dividends" on page 20 of the 1999 Annual Report to Shareholders.

Neither Pacific Gas and Electric Company nor PG&E Corporation made any sales of unregistered equity securities during 1999, the period covered by this report.

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 on page 4 under the heading "Selected Financial Data" in the 1999 Annual Report to Shareholders, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Pacific Gas and Electric Company's ratio of earnings to fixed charges for the year ended December 31, 1999, was 3.25. Pacific Gas and Electric Company's ratio of earnings to combined fixed charges and preferred stock dividends for the year ended December 31, 1999, was 3.08. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959 relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

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 results of operations and financial condition is set forth on pages 5 through 25 under the heading "Management's Discussion and Analysis" in the 1999 Annual Report to Shareholders, 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 1999 Annual Report to Shareholders on page 23 under the heading "Management's Discussion and Analysis--Debt Obligations and Rate Reduction Bonds," on pages 24 and 25 under the heading "Management's Discussion and Analysis--Price Risk Management Activities," and on pages 37, 38, 45, and 47 under Notes 1, 3, and 4 of the "Notes to Consolidated Financial Statements" of the 1999 Annual Report to Shareholders, 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 on pages 26 through 69 of the 1999 Annual Report to Shareholders under the following headings for PG&E Corporation: "Statement of Consolidated Income," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," and "Statement of Consolidated Common Stock Equity;" under the following headings for Pacific Gas and Electric Company: "Statement of Consolidated Income," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," and

"Statement of Consolidated Stockholders' Equity;" and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Report of Independent Public Accountants," and "Responsibility for Consolidated Financial Statements," 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.

Information responding to Item 9 has been previously reported by PG&E Corporation and Pacific Gas and Electric Company in a current report on Form 8-K dated February 17, 1999, and filed on February 23, 1999, as amended by a Current Report on Form 8-K/A filed on June 11, 1999.

PART III

ITEM 10. Directors and Executive Officers of the Registrant.

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included in a separate item captioned "Executive Officers of the Registrant" contained on pages 43 through 45 in Part I of this report. Other information responding to Item 10 is included on pages 3 through 6 under the heading "Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" and page 38 under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the 2000 Joint Proxy Statement relating to the 2000 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 on pages 9 and 10 under the heading "Compensation of Directors" and on pages 30 through 35 under the headings "Summary Compensation Table," "Option/SAR Grants in 1999," "Aggregated Option/SAR Exercises in 1999 and Year-End Option/SAR Values," "Long-Term Incentive Plan--Awards in 1999," "Retirement Benefits," and "Termination of Employment and Change In Control Provisions" in the 2000 Joint Proxy Statement relating to the 2000 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management.

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included on pages 11 and 12 under the heading "Security Ownership of Management" and on page 38 under the heading "Principal Shareholders" in the 2000 Joint Proxy Statement relating to the 2000 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

ITEM 13. Certain Relationships and Related Transactions.

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included on page 10 under the heading "Certain Relationships and Related Transactions" in the 2000 Joint Proxy Statement relating to the 2000 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

PART IV

ITEM 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

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

1. The following consolidated financial statements, supplemental information, and report of independent public accountants contained in the 1999 Annual Report to Shareholders, which have been incorporated by reference in this report:

   Statements of Consolidated Income for the Years Ended December 31, 1999, 1998, and 1997, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Statements of Consolidated Cash Flows for the Years Ended December 31, 1999, 1998, and 1997, for each of PG&E Corporation and Pacific Gas and Electric Company.

   Consolidated Balance Sheets at December 31, 1999, and 1998 for each of PG&E Corporation and Pacific Gas and Electric Company.

   Statement of Consolidated Common Stock Equity for the Years Ended December 31, 1999, 1998, and 1997, for PG&E Corporation.

   Statement of Consolidated Stockholders' Equity for the Years Ended December 31, 1999, 1998, and 1997, for Pacific Gas and Electric Company.

   Notes to Consolidated Financial Statements.

   Quarterly Consolidated Financial Data (Unaudited).

   Independent Auditors' Report (Deloitte & Touche LLP).

2. Independent Auditors' Report (Deloitte & Touche LLP) included at page 53 of this Form 10-K.

3. Report of Independent Public Accountants (Arthur Andersen LLP) included at page 54 of this Form 10-K.

4. Report of Independent Public Accountants (Arthur Andersen LLP) included at page 55 of this Form 10-K.

5. Financial statement schedules:

   I--Condensed Financial Information of Parent for the Years Ended December 31, 1999 and 1998.

   II--Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 1999, 1998 and 1997.

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.

6. Exhibits required to be filed by Item 601 of Regulation S-K:

3.1 Restated Articles of Incorporation of PG&E Corporation effective as of December 19, 1996 (PG&E Corporation's Form 8-B (File No. 1-12609), Exhibit 3.1).

3.2 By-Laws of PG&E Corporation amended as of February 16, 2000.

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3.4 By-Laws of Pacific Gas and Electric Company amended as of February 16, 2000.

4. First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and

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10. The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055. (PG&E Corporation and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit No. 10.2).

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*10.6 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 1999. (PG&E Corporation's Form 10-K for the year ended December 31, 1998 (File No. 1-12609), Exhibit 10.6).

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*10.13 PG&E Corporation Executive Stock Ownership Program, amended as of February 16, 2000.

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12.2 Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company.

13. 1999 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company--portions of the 1999 Annual Report to Shareholders under the headings "Selected Financial Data," "Management's Discussion and Analysis," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Statement of Consolidated Income," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Common Stock Equity," financial statements of Pacific Gas and Electric Company entitled "Statement of Consolidated Income," "Consolidated Balance Sheet," "Statement of Consolidated Cash Flows," "Statement of Consolidated Stockholders' Equity," "Notes to Consolidated Financial Statements" and "Quarterly Consolidated Financial Data (Unaudited)" are included only. (Except for those portions that are expressly incorporated herein by reference, such 1999 Annual Report to Shareholders is furnished for the information of the Commission and is not deemed to be "filed" herein.)

18. Letter re change in Accounting Principles.

21. Subsidiaries of the Registrant.

23.1 Consent of Deloitte & Touche LLP.

23.2 Consent of Arthur Andersen 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.

27.1 Financial Data Schedule for the year ended December 31, 1999, for PG&E Corporation.

27.2 Financial Data Schedule for the year ended December 31, 1999, for Pacific Gas and Electric Company.

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* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

The exhibits filed herewith are attached hereto (except as noted) and those indicated above which are not filed herewith were previously filed with the Commission and are hereby incorporated by reference. All exhibits filed herewith or incorporated by reference are filed with respect to both PG&E Corporation (File No. 1-12609) and Pacific Gas and Electric Company (File No. 1-2348), unless otherwise noted. Exhibits will be furnished to security holders of PG&E Corporation or Pacific Gas and Electric Company upon written request and payment of a fee of $0.30 per page, which fee covers only the registrants' reasonable expenses in furnishing such exhibits. The registrants agree to furnish to the Commission upon request a copy of any instrument defining the rights of long-term debt holders not otherwise required to be filed hereunder.

(b) Reports on Form 8-K

Reports on Form 8-K(/1/) during the quarter ended December 31, 1999, and through the date hereof:

1. October 1, 1999

Item 5. Other Events--Reporting the filing of an application relating to the proposed auction of Pacific Gas and Electric Company's hydroelectric generation assets

2. October 20, 1999

Item 5. Other Events--Proposed decision in Pacific Gas and Electric Company's General Rate Case

3. October 21, 1999--Filed by PG&E Corporation only

Item 5. Other Events--
A. Share Repurchase
B. Proposed amendments to Articles of Incorporation and Bylaw Amendments

4. November 5, 1999

Item 5. Other Events--
A. Pacific Gas and Electric Company's Post-transition Period Ratemaking Proceeding
B. Pacific Gas and Electric Company's 2000 Cost of Capital Proceeding

5. December 1, 1999

Item 5. Other Events--Performance Goals and Implementation Strategy

6. January 21, 2000

Item 5. Other Events--
A. Pacific Gas and Electric Company's General Rate Case Proceeding
B. Proposed Auction of Pacific Gas and Electric Company's Hydroelectric Generating Assets
C. 1998 Annual Transition Cost Proceeding

7. January 31, 2000

Item 5. Other Events--Sale of Texas Gas Transmission Companies

8. February 23, 2000

Item 5. Other Events--
A. Pacific Gas and Electric Company's General Rate Case Proceeding
B. 1998 Annual Transition Cost Proceeding
C. Disposition of PG&E Energy Services Corporation

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(1) Unless otherwise noted, all reports were filed under Commission File Number 1-2348 (Pacific Gas and Electric Company) and Commission File Number 1-12609 (PG&E Corporation)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized, in the City and County of San Francisco, on the 6th day of March, 2000.

PG&E CORPORATION (Registrant)	PACIFIC GAS AND ELECTRIC COMPANY (Registrant)
By /s/ Gary P. Encinas	By /s/ Gary P. Encinas
(Gary P. Encinas, Attorney-in-Fact)	(Gary P. Encinas, Attorney-in-Fact)

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		
*ROBERT D. GLYNN, JR.	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation)	March 6, 2000
*GORDON R. SMITH	President and Chief Executive Officer (Pacific Gas and Electric Company)	March 6, 2000
B. Principal Financial Officers		
*PETER A. DARBEE	Senior Vice President, Chief Financial Officer, and Treasurer (PG&E Corporation)	March 6, 2000
*KENT M. HARVEY	Senior Vice President, Chief Financial Officer, Controller, and Treasurer (Pacific Gas and Electric Company)	March 6, 2000
C. Principal Accounting Officers		
*CHRISTOPHER P. JOHNS	Vice President and Controller (PG&E Corporation)	March 6, 2000
*KENT M. HARVEY	Senior Vice President, Chief Financial Officer, Controller, and Treasurer (Pacific Gas and Electric Company)	March 6, 2000
D. Directors		
*RICHARD A. CLARKE *HARRY M. CONGER *DAVID A. COULTER *C. LEE COX *WILLIAM S. DAVILA *ROBERT D. GLYNN, JR. *DAVID M. LAWRENCE, M.D. *MARY S. METZ *CARL E. REICHARDT *JOHN C. SAWHILL *GORDON R. SMITH (Director of Pacific Gas and	Directors of PG&E Corporation and Pacific Gas and Electric Company, except as noted	March 6, 2000

Electric Company, cnly)
*BARRY LAWSON WILLIAMS

*By /s/ Gary P. Encinas

(Gary P. Encinas, Attorney-in-Fact)

INDEPENDENT AUDITORS' REPORT

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

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements as of and for the year ended December 31, 1999 included in the PG&E Corporation and Pacific Gas and Electric Company Annual Report to Shareholders incorporated by reference in this Form 10-K, and have issued our report thereon dated March 3, 2000. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedules listed in Part IV, Item 14. (a)(5) in this Form 10-K are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company and are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the consolidated financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the consolidated financial statements taken as a whole.

Deloitte & Touche LLP

San Francisco, California
March 3, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements as of December 31, 1998, and for each of the two years in the period ended December 31, 1998 included in the PG&E Corporation and Pacific Gas and Electric Company Annual Report to Shareholders incorporated by reference in this Form 10-K, and have issued our report thereon dated February 8, 1999. Our audits were made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The Condensed Financial Information of Parent for the Year Ended December 31, 1998 and the Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 1998 and 1997, are the responsibility of the management of PG&E Corporation and of Pacific Gas and Electric Company. These schedules are for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic consolidated financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

ARTHUR ANDERSEN LLP

San Francisco, California
February 8, 1999

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying consolidated balance sheets of PG&E Corporation (a California corporation) and subsidiaries and Pacific Gas and Electric Company (a California corporation) and subsidiaries as of December 31, 1998, and the related statements of consolidated income, cash flows, and common stock equity of PG&E Corporation and subsidiaries and the related statements of consolidated income, cash flows and stockholders' equity of Pacific Gas and Electric Company and subsidiaries for each of the two years in the period ended December 31, 1998. These financial statements are the responsibility of the management of PG&E Corporation and Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial positions of PG&E Corporation and subsidiaries, and of Pacific Gas and Electric Company and subsidiaries, as of December 31, 1998, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

San Francisco, California
February 8, 1999

SCHEDULE I--CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS

	December 31, 1999	December 31, 1998
	(in millions)	
Assets:		
Cash and cash equivalents	$ 155	$ 9
Advances to affiliates	299	448
Other current assets	--	2
Total current assets	454	459
Equipment	16	8
Accumulated depreciation	(3)	(1)
Net equipment	13	7
Investments in subsidiaries	7,621	8,780
Other investments	52	41
Deferred income taxes	396	--
Other deferred charges	--	1
Total Assets	$8,536	$9,288
Liabilities and Stockholders' Equity:		
Current Liabilities		
Short-term borrowings	$526	$ 683
Accounts payable - related parties	76	221
Accounts payable - trade	10	9
Accrued taxes	117	155
Dividends payable	110	115
Other	112	16
Total current liabilities	951	1,199
Noncurrent Liabilities		
Deferred income taxes	--	19
Other	5	4
Total noncurrent liabilities	5	23
Stockholders' Equity		
Common stock	5,906	5,862
Reinvested earnings	1,674	2,204
Total stockholders' equity	7,580	8,066
Total Liabilities and Stockholders' Equity	$8,536	$9,288

SCHEDULE I--CONDENSED FINANCIAL INFORMATION FOR PARENT--(Continued)

CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 1999, 1998 and 1997

	1999	1998	1997
	(in millions, except per share amounts)		
Equity in earnings of subsidiaries	$ 853	$ 736	$ 772
Operating expenses	(4)	1	(21)
Loss on assets held for sale	(1,275)	--	--
Interest expense	(30)	(52)	(23)
Other income	16	5	--
Income Before Income Taxes	(440)	690	728
Less: Income taxes	(447)	(83)	(17)
Income from continuing operations	$ 7	$ 773	$ 716
Discontinued operations	(98)	(52)	(29)
Cumulative effect of a change in an accounting principle	12	--	--
Net income (loss) before intercompany elimination	$ (79)	$ 721	$ 716
Elimination of intercompany (profit) loss	6	(2)	--
Net income (loss)	$ (73)	$ 719	$ 716
Weighted Average Common Shares Outstanding	368	382	410
Earnings Per Common Share, Basic and Diluted	$ (.20)	$ 1.88	$ 1.75

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 1999, 1998 and 1997

	1999	1998	1997
	(in millions)		
Cash Flows From Operating Activities			
Net income (loss)	$ (73)	$ 721	$ 716
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of subsidiaries	(853)	(736)	(772)
Deferred taxes	(415)	19	--
Loss on assets held for sale	1,275	--	--
Dividends received from consolidated subsidiaries	527	445	763
Other--net	77	(574)	(605)
Net cash provided (used) by operating activities	$ 538	$ (125)	$ 1,312

Cash Flows From Investing Activities			
Capital expenditures	(8)	(8)	--
Investments in subsidiaries	(722)	(575)	(150)
Return of capital by Utility (share repurchases)	926	1,600	--
Other--net	(12)	--	--
Net cash provided by investing activities	$ 184	$ 1,017	$ (150)
Cash Flows From Financing Activities			
Common stock issued	54	63	--
Common stock repurchased	(3)	(1,158)	(804)
Short-term debt issued (redeemed)--net	(157)	683	--
Dividends paid	(465)	(470)	(367)
Other--net	(5)	(2)	10
Net cash used by financing activities	$ (576)	$ (884)	$ (1,161)
Net Change in Cash and Cash Equivalents	146	8	1
Cash and Cash Equivalents at January 1	9	1	--
Cash and Cash Equivalents at December 31	$ 155	$ 9	$ 1

PG&E CORPORATION

SCHEDULE II--CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 1999, 1998, and 1997

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in thousands)			
Valuation and qualifying accounts deducted from assets:					
1999:					
Allowance for uncollectible accounts (2)...................	$58,577	$25,243	$ (183)	$18,509(1)	$65,128
1998:					
Allowance for uncollectible accounts (2)...................	$72,912	$10,978	$(2,893)	$22,420(1)	$58,577
1997:					
Allowance for uncollectible accounts (2)...................	$57,904	$42,500	$ --	$27,492(1)	$72,912

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

(2) Allowance for uncollectible accounts are deducted from "Accounts receivable--Customers, net" and "Accounts receivable--Energy Marketing."

PACIFIC GAS AND ELECTRIC COMPANY

SCHEDULE II--CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the years ended December 31, 1999, 1998, and 1997

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in thousands)			
Valuation and qualifying accounts deducted from assets:					
1999:					
Allowance for uncollectible accounts (2)	$47,347	$17,011	$ 44	$17,981(1)	$46,421
1998:					
Allowance for uncollectible accounts (2)	$59,608	$10,007	$ 152	$22,420(1)	$47,347
1997:					
Allowance for uncollectible accounts (2)	$57,904	$30,718	$(1,836)	$27,178(1)	$59,608

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27.2	Financial Data Schedule for the year ended December 31, 1999, for Pacific Gas and Electric Company.........................

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* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

The exhibits filed herewith are attached hereto (except as noted) and those indicated above which are not filed herewith were previously filed with the Commission and are hereby incorporated by reference. All exhibits filed herewith or incorporated by reference are filed with respect to both PG&E Corporation (File No. 1-12609) and Pacific Gas and Electric Company (File No. 1-2348), unless otherwise noted. Exhibits will be furnished to security holders of PG&E Corporation or Pacific Gas and Electric Company upon written request and payment of a fee of $0.30 per page, which fee covers only the registrants' reasonable expenses in furnishing such exhibits. The registrants agree to furnish to the Commission upon request a copy of any instrument defining the rights of long-term debt holders not otherwise required to be filed hereunder.

FORM 10-Q
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2000

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	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, California 94177

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California 94105

(Address of principal executive offices) (Zip Code)

Pacific Gas and Electric Company
(415) 973-7000

PG&E Corporation
(415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.
Yes X No _________

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock Outstanding October 26, 2000:
PG&E Corporation 387,095,350 shares
Pacific Gas and Electric Company Wholly owned by PG&E Corporation

PG&E CORPORATION
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2000
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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED INCOME STATEMENT
(in millions, except per share amounts)

	Three months ended September 30, 2000	Three months ended September 30, 1999 (1)	Nine months ended September 30, 2000	Nine months ended September 30, 1999 (1)
Operating revenues				
Utility	$ 2,523	$ 2,587	$ 7,037	$ 6,905

Energy commodities and services	4,981	3,630	11,113	9,120
Total operating revenues	7,504	6,217	18,150	16,025
Operating expenses				
Cost of energy for utility	2,234	864	4,187	2,183
Deferred electric procurement costs	(2,176)	-	(2,789)	-
Cost of energy commodities and services	4,618	3,394	10,137	8,415
Operating and maintenance	960	765	2,420	2,294
Depreciation, amortization and decommissioning	1,239	678	2,268	1,676
Total operating expenses	6,875	5,701	16,223	14,568
Operating income	629	516	1,927	1,457
Interest expense, net	191	190	556	583
Other income, net	45	20	72	81
Income before income taxes	483	346	1,443	955
Income taxes	239	149	671	395
Income from continuing operations	244	197	772	560
Discontinued operations				
Loss from operations of PG&E Energy Services (net of applicable income taxes of $9 million and $26 million, respectively)	-	(12)	-	(34)
Loss on disposal of PG&E Energy Services (net of applicable incomes taxes of $13 million)	(19)	-	(19)	-
Income before cumulative effect of change in accounting principle	225	185	753	526
Cumulative effect of change in accounting principle (net of applicable income taxes of $8 million)	-	-	-	12
Net income	$ 225	$ 185	$ 753	$ 538
Weighted Average Common Shares Outstanding	362	367	361	369
Earnings per common share, basic				
Income from continuing operations	$ .67	$ .53	$ 2.14	$ 1.52
Discontinued operations	(.05)	(.03)	(.05)	(.09)
Cumulative effect of accounting change	-	-	-	.03
	$ .62	$ .50	$ 2.09	$ 1.46
Earnings per common share, diluted				
Income from continuing operations	$ .67	$ .53	$ 2.12	$ 1.51
Discontinued operations	(.05)	(.03)	(.05)	(.09)
Cumulative effect of accounting change	-	-	-	.03
	$ .62	$ .50	$ 2.07	$ 1.45
Dividends declared per common share	$ .30	$ .30	$ .90	$ .90

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.

(1) Amounts have been restated to reflect the change in accounting for major maintenance and overhauls at the PG&E National Energy Group (see Note 1 of the Notes to the Condensed Consolidated Financial Statements), and reclassification of PG&E Energy Services operating results to discontinued operations. The accounting change resulted in a cumulative effect being recorded as of January 1, 1999, of $12 million ($0.03 per share), net of income taxes of $8 million. Operating income previously reported for the third quarter of 1999 was $492 million. Net income previously reported for the third quarter of 1999 was $183 million ($0.50 per share).
</TABLE

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEET (in millions)

	Balance at	
	September 30, 2000	December 31, 1999
ASSETS		
Current assets		
Cash and cash equivalents	$ 304	$ 281
Short-term investments	819	187
Accounts receivable		
Customers, net	1,641	1,486
Energy marketing	1,187	532
Price risk management	776	607
Inventories and prepayments	987	598
Deferred income taxes	-	133
Total current assets	5,714	3,824
Property, plant, and equipment		
Utility	23,201	23,001
Non-utility		
Electric generation	1,976	1,905
Gas transmission	2,522	2,541
Construction work in progress	686	436
Other	151	184
Total property, plant, and equipment (at original cost)	28,536	28,067
Accumulated depreciation and decommissioning	(11,485)	(11,291)
Property, plant, and equipment, net	17,051	16,776
Other noncurrent assets		
Regulatory assets	6,726	4,957
Nuclear decommissioning funds	1,385	1,264
Other	3,015	2,894
Total noncurrent assets	11,126	9,115
TOTAL ASSETS	$ 33,891	$ 29,715

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEET (in millions)

	Balance at September 30, 2000	Balance at December 31, 1999
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 2,369	$ 1,499
Current portion of long-term debt	616	592
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	2,002	708
Other	315	559
Regulatory balancing accounts	24	384
Energy marketing	1,234	480
Accrued taxes	-	211
Price risk management	646	575
Other	1,182	1,033
Total current liabilities	8,678	6,331
Noncurrent liabilities		
Long-term debt	6,512	6,673
Rate reduction bonds	1,817	2,031
Deferred income taxes	3,628	3,147
Deferred tax credits	162	231
Other	4,920	3,636
Total noncurrent liabilities	17,039	15,718
Preferred stock of subsidiaries	480	480
Utility obligated mandatorily redeemable preferred securities of trust holding solely utility subordinated debentures	300	300
Common stockholders' equity		
Common stock, no par value, authorized 800,000,000 shares, issued, 386,703,729 and 384,406,113 shares, respectively	5,958	5,906
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Reinvested earnings	2,126	1,670
Total common stockholders' equity	7,394	6,886
Commitments and contingencies (Notes 2 and 6)	-	-
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 33,891	$ 29,715

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.

PG&E CORPORATION
STATEMENT OF CONDENSED CONSOLIDATED CASH FLOWS (in millions)

	For the nine months ended September 30, 2000	1999
Cash flows from operating activities		
Net income	$ 753	$ 538
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on disposal of businesses	19	-
Depreciation, amortization and decommissioning	2,268	1,684
Deferred electric procurement costs	(2,789)	-
Deferred income taxes and tax credits-net	545	(652)
Other deferred charges and noncurrent liabilities	861	(729)
Cumulative effect of change in accounting principle	-	(12)
Changes in operating assets and liabilities,net of effect of discontinued operations:		
Short-term investments	(632)	18
Accounts receivable - trade	(810)	(225)
Regulatory balancing accounts payable	(360)	855
Inventories and prepayments	(194)	36
Price risk management assets and liabilities, net	(98)	22
Accounts payable - trade	1,294	(224)
Accrued taxes	(211)	309
Other working capital	536	64
Other-net	28	339
Net cash provided by operating activities	1,210	2,023
Cash flows from investing activities		
Capital expenditures	(1,220)	(1,058)
Net proceeds from sales of businesses	103	1,014
Other-net	(316)	108
Net cash provided by investing activities	(1,433)	64
Cash flows from financing activities		
Net borrowings (repayments) under credit facilities	894	(682)
Long-term debt matured, redeemed, or repurchased	(432)	(611)
Long-term debt issued	57	-
Common stock issued	52	44
Common stock repurchased	-	(534)
Dividends paid	(325)	(335)
Other-net	-	14
Net cash provided by financing activities	246	(2,104)
Net change in cash and cash equivalents	23	(17)
Cash and cash equivalents at January 1	281	286
Cash and cash equivalents at September 30	$ 304	$ 269

Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 471	$ 518
Income taxes (net of refunds)	$ 23	$ 589

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.
</TABLE

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED INCOME STATEMENT (in millions)

	Three months ended September 30,		Nine months ended September 30,	
	2000	1999	2000	1999
Operating revenues				
Electric utility	$ 1,999	$ 2,189	$ 5,401	$ 5,550
Gas utility	524	398	1,636	1,355
Total operating revenues	2,523	2,587	7,037	6,905
Operating expenses				
Cost of electric energy	2,056	746	3,544	1,681
Deferred electric procurement costs	(2,176)	-	(2,789)	-
Cost of gas	178	118	643	502
Operating and maintenance,	730	615	1,824	1,849
Depreciation, amortization, and decommissioning	1,202	622	2,160	1,513
Total operating expenses	1,990	2,101	5,382	5,545
Operating income	533	486	1,655	1,360
Interest expense, net	150	148	435	450
Other income, net	30	8	47	30
Income before income taxes	413	346	1,267	940
Income taxes	196	161	594	424
Net income	217	185	673	516
Preferred dividend requirement	6	6	18	18
Income available for common stock	$ 211	$ 179	$ 655	$ 498

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.
</TABLE

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEET (in millions)

	Balance at	
	September 30, 2000	December 31, 1999
ASSETS		
Current assets		
Cash and cash equivalents	$ 68	$ 80
Short-term investments	242	21
Accounts receivable, net	1,327	1,210
Inventories	283	294
Prepayments	56	34
Income tax receivable	295	-
Deferred income taxes	-	119
Total current assets	2,271	1,758
Property, plant, and equipment		
Electric	15,718	15,762
Gas	7,483	7,239
Construction work in progress	228	214
Total property, plant, and equipment (at original cost)	23,429	23,215
Accumulated depreciation and decommissioning	(10,616)	(10,497)
Property, plant, and equipment, net	12,813	12,718
Other noncurrent assets		
Regulatory assets	6,650	4,895
Nuclear decommissioning funds	1,385	1,264
Other	1,064	835
Total noncurrent assets	9,099	6,994
TOTAL ASSETS	$ 24,183	$ 21,470

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEET (in millions)

Balance at	
September 30, 2000	December 31, 1999

LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 917	$ 449
Current portion of long-term debt	399	465
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	1,859	577
Related parties	27	216
Regulatory balancing accounts	24	384
Other	347	333
Accrued taxes	-	118
Deferred income taxes	10	-
Other	644	529
	--------	-------
Total current liabilities	4,517	3,361
Noncurrent liabilities		
Long-term debt	4,866	4,877
Rate reduction bonds	1,817	2,031
Deferred income taxes	2,991	2,510
Deferred tax credits	161	231
Other	3,606	2,252
	-------	-------
Total noncurrent liabilities	13,441	11,901
Preferred stock with mandatory redemption provisions 6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	137	137
Company obligated mandatorily redeemable preferred securities of trust holding solely utility subordinated debentures 7.90%, 12,000,000 shares due 2025	300	300
Stockholders' equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable - 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable - 4.36% to 7.04%, outstanding 5,973,456 shares	142	149
Common stock, $5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 and 7,627,765 shares, respectively	(475)	(200)
Additional paid in capital	1,971	1,964
Reinvested earnings	2,399	2,107
	--------	--------
Total stockholders' equity	5,788	5,771
Commitments and contingencies (Notes 2 and 6)	-	-
	--------	--------
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	24,183	$ 21,470
	========	========

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF CONDENSED CONSOLIDATED CASH FLOWS (in millions)

For the nine months ended
September 30,

	2000	1999
Cash flows from operating activities		
Net income	$ 673	$ 516
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	2,160	1,513
Deferred electric procurement costs	(2,789)	-
Deferred income taxes and tax credits-net	540	(799)
Other deferred charges and noncurrent liabilities	640	(496)
Net effect of changes in operating assets and liabilities:		
Short-term investments	(221)	(3)
Accounts receivable	(117)	128
Regulatory balancing accounts payable	(360)	855
Inventories and prepayments	(306)	12
Accounts payable - trade	1,093	(100)
Accrued taxes	(118)	231
Other working capital	122	(10)
Other-net	(20)	76
Net cash provided by operating activities	1,297	1,923
Cash flows from investing activities		
Capital expenditures	(874)	(848)
Proceeds from sale of assets	-	1,014
Other-net	38	21
Net cash used by investing activities	(836)	187
Cash flows from financing activities		
Net borrowings (repayments) under credit facilities	468	(591)
Long-term debt matured, redeemed, or repurchased	(291)	(474)
Common stock repurchased	(275)	(725)
Dividends paid	(375)	(309)
Net cash used by financing activities	(473)	(2,099)
Net change in cash and cash equivalents	(12)	11
Cash and cash equivalents at January 1	80	73
Cash and cash equivalents at September 30	$ 68	$ 84
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest (net of amounts capitalized)	$ 295	$ 363
Income taxes (net of refunds)	$ -	$ 852

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part of this statement.
</TABLE

PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Basis of Presentation

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and Pacific Gas and Electric Company (the Utility), a regulated subsidiary of PG&E Corporation. The Notes to Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's condensed consolidated financial statements include the accounts of PG&E Corporation and its wholly owned and controlled subsidiaries, including the Utility (collectively, the Corporation). The Utility's condensed consolidated financial statements include its accounts as well as those of its wholly owned and controlled subsidiaries.

The Utility's financial position and results of operations are the principal factors affecting the Corporation's consolidated financial position and results of operations. This quarterly report should be read in conjunction with the Corporation's and the Utility's Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements incorporated by reference in their combined 1999 Annual Report on Form 10-K, and the Corporation's and the Utility's other reports filed with the Securities and Exchange Commission since their 1999 Form 10-K was filed.

PG&E Corporation and the Utility believe that the accompanying condensed consolidated statements reflect all adjustments that are necessary to present a fair statement of the condensed consolidated financial position and results of operations for the interim periods. All material adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q. All significant intercompany transactions have been eliminated from the condensed consolidated financial statements.

Certain amounts in the prior year's condensed consolidated financial statements have been reclassified to conform to the 2000 presentation. Results of operations for interim periods are not necessarily indicative of results to be expected for a full year.

Effective January 1, 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls at PG&E National Energy Group. Beginning January 1, 1999, the costs of major maintenance and overhauls, principally at PG&E Generating Company (PG&E Gen), have been accounted for as incurred. Previously, the estimated cost of major maintenance and overhauls was accrued in advance in a systematic and rational manner over the period between major maintenance and overhauls. The change resulted in PG&E Corporation recording income of $12 million net of income tax of $8 million, reflecting the cumulative effect of the change in accounting principle. The Utility consistently has accounted for major maintenance and overhauls as incurred.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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. Actual results could differ from these estimates.

PG&E Corporation expects to adopt Statement of Financial Accounting Standards (SFAS) No. 133, as amended by SFAS No. 138, effective January 1, 2001. The Statement will require that the Company recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. The Corporation currently is evaluating what the effect of SFAS No. 133 will be on the earnings and financial position of PG&E Corporation. However, the mark-to-market method of accounting is already applied for commodity non-hedging and risk management activities.

NOTE 2: THE CALIFORNIA ELECTRIC INDUSTRY

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a market framework for electric generation. Today, most Californians may continue to purchase their electricity from investor-owned utilities such as Pacific Gas and Electric Company, or they may choose to purchase electricity from alternative generation providers (such as independent power generators and retail electricity suppliers such as marketers, brokers, and aggregators). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as the Utility, continue to be the generation providers. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including customers who choose an alternative generation provider.

An Independent System Operator (ISO) and a Power Exchange (PX) operate in California. The PX provides a process to establish market-clearing prices for electricity in the markets operated by the PX. The ISO schedules delivery of electricity for all market participants and operates the real-time and ancillary services markets for electricity. (Ancillary services are needed to maintain the reliability of the electric grid.) The Utility continues to own and maintain its transmission system, but the ISO controls the operation of the system. During the transition period, the Utility is required to bid or schedule into the PX and ISO markets all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators. On August 3, 2000, the California Public Utilities Commission (CPUC) authorized the Utility to purchase energy and ancillary services and capacity products for retail customers in wholesale markets outside the PX and to set up memorandum accounts to track related costs. Such transactions are confined to previous limits established for forward market purchases and must expire before December 31, 2005.

Competitive Market Framework

Beginning in June 2000, the Utility has experienced unanticipated and massive increases (above the generation-related costs component embedded in frozen rates) in the wholesale costs of the electric energy that is purchased from the PX on behalf of its retail customers. The average price that the PX charged the Utility for electric power in the months of June, July, August, and September 2000, was approximately 16.3 cents per kilowatt-hour (kWh), 11.0 cents per kWh, 18.7 cents per kWh and 14.0 cents per kWh, respectively, compared to 3.0, 3.9, 4.1 and 4.0 cents per kWh for the same months in 1999. The generation-related cost component that is embedded in frozen rates and available for payment of wholesale electric power costs during those same periods was approximately 5.4 cents per kWh. The forward curve for power prices in the California market suggests that these costs may remain well above the embedded cost component of frozen rates through the end of this year and beyond next summer unless significant changes occur in the wholesale power market.

As a result, the Utility has incurred and continues to incur expenses representing the excess of power purchase costs above the generation component embedded in frozen rates. Such expenses are deferred to a regulatory balancing account called the Transition Revenue Account (TRA). The TRA balance as of September 30, 2000 was approximately $2.9 billion. The TRA balance does not reflect the Utility's revenues from (1) sales of energy from retained generation facilities to the PX in excess of authorized costs or (2) the amount by which the PX prices exceed the purchase price contained in the Utility's long-term contracts to purchase energy from Qualifying Facilities (QF) and other power providers. Approximately half of the Utility's suppliers under QF contracts have elected to receive PX based prices for energy in addition to contractual capacity payments. The Utility expects that most remaining QF generators will elect to receive PX prices for their energy payments by summer 2001. The Utility pays these suppliers directly, rather than through the PX, but receives billing credits for energy delivered to the PX from QFs.

A prior CPUC decision would prohibit the Utility from collecting after the transition period certain electric costs incurred during the transition period but not recovered from frozen rates during that period, including TRA under-collections. The CPUC decision also would prohibit offsetting these specific under-collected balances against over-collected transition costs. The Utility is seeking judicial review by the California Supreme Court. The Utility's petition is pending.

On October 4, 2000, the Utility and Southern California Edison Company filed separate emergency petitions with the CPUC to rescind and modify as necessary prior decisions prohibiting utilities from carrying over costs incurred during the rate freeze to the post-rate freeze period. The utilities noted that many parties have acknowledged that the wholesale electric power market is not workably competitive and that the significant increases in prices were not considered in the CPUC's original rulings. On October 17, 2000, the administrative law judge (ALJ) and the CPUC commissioner assigned to review the emergency petitions issued a joint ruling indicating that they would reconsider the accounting mechanisms established in prior CPUC decisions and adopt a schedule that permits a decision by the end of the year.

In response to the above ruling, the Utility filed its proposals requesting that the CPUC modify its prior decisions to authorize the utilities to transfer any unrecovered balance in the TRA as of the end of the rate freeze into a new balancing account, and authorize recovery of the balance in that new account over a period not to exceed four years, subject to a rate stabilization plan to be addressed in a second phase of the proceeding. The Utility asked the CPUC to adopt an expedited procedural schedule in a second phase that would, not later than March 31, 2001, resolve the following issues: (1) implementation of when and how the rate freeze is to be ended; (2) adoption of post rate freeze tariffs and rates; (3) approval of the rate stabilization plan; and (4) adoption of the retail rate components for recovery of the new balancing account. The Utility indicated that it will submit its detailed proposals on the rate stabilization plan and tariffs by November 15, 2000.

At the prehearing conference held on October 27, 2000, the ALJ indicated that the scope of the proceeding was solely to consider accounting mechanisms to reduce the TRA under-collections and that the Utility's proposals for interim relief were broader than contemplated in the October 17th ruling, were not consistent with the CPUC's prior decisions precluding carryover of under-collected TRA costs, and would not be considered in the proceeding before the end of the year. However, the ALJ indicated that the CPUC would consider proposals made by The Utility Reform Network (TURN), a consumer group, to transfer TRA under-collections to the Transition Cost Balancing Account (TCBA) discussed below. TURN's proposals would treat under-collected electric procurement costs for accounting purposes as if such costs were unrecovered transition costs, the likely effect of which would be to delay the completion of transition cost recovery by the Utility as well as delay the end of the rate freeze. If TURN's proposal were adopted, the Utility would have to write-off any unrecovered transition costs remaining in the TCBA if such costs were not probable of recovery. The ALJ ordered the parties to respond to the utilities' emergency petitions and to TURN's proposal by November 9, 2000.

The Utility reviews on an ongoing basis the facts and circumstances relating to the TRA under-collections. The Utility currently believes recovery of the TRA under-collections is probable. TRA under-collections are recorded as a regulatory asset on the balance sheet rather than being charged to earnings because it is probable that these under-collections will be recovered through the ratemaking process. However, ultimate recovery is dependent upon the favorable outcome of the regulatory actions described above, as well as upon other factors such as future market prices of electricity and future fuel prices that, in part, are influenced by sales level, and economic conditions, about which there can be no certainty. If regulatory or judicial relief is not forthcoming, and if the Utility determines that its uncollected wholesale power purchase costs are not probable of recovery, then the Utility would be required to write off the unrecoverable portion as a charge against earnings. In addition, the Utility would be unable to continue deferring these costs incurred during the transition period and such expenses would reduce the Utility's future earnings accordingly. With respect to wholesale power purchase costs incurred after the end of the transition period and prior to any adjustment in rates, the Utility may be able to defer these costs if it determines that they are probable of recovery.

The Utility is actively exploring ways to reduce its exposure to the higher power purchase costs and its corresponding TRA balance, including working with interested parties to address power market dysfunction before appropriate regulatory bodies and hedging a portion of its open procurement position against higher purchase power costs through forward purchases. The CPUC only recently authorized the Utility to enter into bilateral power purchase contracts. In October 2000, the Utility entered into bilateral power purchase contracts with several suppliers.

On October 16, 2000, the Utility joined with Southern California Edison and TURN in filing a petition with the Federal Energy Regulatory Commission (FERC) requesting that the FERC (1) immediately find the California wholesale electricity market to be not workably competitive and the resulting prices to be unjust and unreasonable; (2) immediately impose a cap on the price for energy and ancillary services; and (3) institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions, and responsibility for refunds. However, the reduced price cap requested, even if approved, would still be above the approximate 5.4 cents per kWh embedded in frozen rates for the payment of the Utility's wholesale power purchase costs. Also, on October 20, 2000, the ISO filed a market stabilization plan with the FERC requesting the FERC to impose a price cap of $100 per megawatt-hour (Mwh) (10 cents per kWh) for generators who do not enter into contracts to supply 70 percent of their supply to serve California customers. There are certain other exemptions to the $100 price cap. The existing $250 price cap per Mwh hour (25 cents per kWh) would apply to generators who are exempt from the $100 per Mwh hour price cap. The ISO also has recommended that buyers (utilities) be required to contract for 85 percent of their customer requirements for power in advance of when the power is needed. Further, the ISO has adopted additional load based price caps for the real-time and ancillary service markets which would range between $65 and $250 per Mwh. These price caps would begin as soon as November 3, 2000, and remain in place until real-time and ancillary service markets have demonstrated that they are workably competitive under a variety of load conditions.

A Joint Resolution of the California legislature called on the CPUC to initiate an investigation to review the impact of the current electricity crisis on consumers and California investor-owned utilities with emphasis on the options for correcting the electricity market, methods to eliminate price volatility for consumers, and importantly, methods for cost recovery and cost allocation. In response, the CPUC issued an order on September 7, 2000 expanding an existing investigation into the wholesale electric market and the associated impact on electric rates to include the issues identified by the legislature.

For the three and nine months ended September 30, 2000 and 1999, the cost of electric energy for the Utility, reflected on the Condensed Consolidated Income Statement, is comprised of the cost of fuel for electric generation and QF purchases, the cost of PX purchases, and ancillary services charged by the ISO, net of sales to the PX, as follows:

	Three months ended September 30, 2000	Three months ended September 30, 1999	Nine months ended September 30, 2000	Nine months ended September 30, 1999
(in millions)				
Cost of fuel for electric generation and QF purchases	$ 592	$ 409	$ 1,203	$ 1,178
Cost of purchases from the PX and ISO	2,132	554	3,492	1,101
Proceeds from sales to the PX	(668)	(217)	(1,151)	(598)
Total Utility cost of electric energy	$ 2,056	$ 746	$ 3,544	$ 1,681

Transition Period, Rate Freeze, and Rate Reduction

California's electric industry restructuring established a transition period during which electric rates remain frozen at 1996 levels (with the exception that, on January 1, 1998, rates for small commercial and residential customers were reduced by 10 percent and remain frozen at this reduced level) and investor-owned utilities may recover their transition costs. Transition costs are generation-related costs that prove to be uneconomic under the new industry structure. The transition period ends the earlier of December 31, 2001, or when the particular utility has recovered its eligible transition costs.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service will not increase the Utility customers' electric rates. If the transition period ends before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, nuclear decommissioning, rate reduction bond debt service, and the cost of procuring electricity for the Utility's retail customers. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the competition transition charge (CTC), which recovers the transition costs. These CTC revenues are being recovered from all Utility distribution customers and are subject to seasonal fluctuations in the Utility's sales volumes, fluctuating PX energy prices, and certain other factors. The CTC is collected regardless of the customer's choice of electricity supplier (i.e., the CTC is non-bypassable).

Transition Cost Recovery

Although most transition costs must be recovered during the transition period, certain transition costs can be recovered after the transition period. Except for the transition costs discussed below, at the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues.

Transition costs consist of (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and that were included in customers' rates on December 20, 1995) and future sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from qualifying facilities and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods, to be included in rates in subsequent periods.)

Above-market sunk costs result when the book value of a facility exceeds its market value. Conversely, below-market sunk costs result when the market value of a facility exceeds its book value. The total amount of generation facility costs to be included as transition costs is based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. Revenues generated from the Utility's sales to the PX and ISO that exceed authorized costs are also used to offset transition costs.

For nuclear transition costs, revenues provided for transition cost recovery are based on the accelerated recovery of the investment in Diablo Canyon Nuclear Power Plant (Diablo Canyon) over a five-year period ending December 31, 2001.

Costs associated with the Utility's long-term contracts to purchase electric power are included as transition costs. Regulation required the Utility to enter into long-term agreements with non-utility generators to purchase electric power at fixed prices. Prices fixed under these contracts have generally been above prices for power in wholesale markets. Over the remaining life of these contracts, the Utility estimates that it will purchase 299 million MWh of electric power. The contracts expire at various dates through 2028. To the extent that the individual contract prices are above the market price, the Utility is collecting the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. To the extent that the contracted prices are below the market price, the Utility is using the savings to offset other transition costs during the transition period.

The total costs under long-term contracts are based on several variables, including the capacity factors of the related generating facilities and future market prices for electricity. For the nine months ended September 30, 2000 and 1999, the average price paid under the Utility's long-term contracts for electricity was 7.8 cents and 6.4 cents per kWh, respectively.

At September 30, 2000, and December 31, 1999, the Utility's net generation-related regulatory assets (excluding the TRA) totaled $2.6 billion and $4.0 billion, respectively. Included in the generation-related regulatory assets at September 30, 2000, is $2.1 billion associated with the valuation of the Utility's hydroelectric generation facilities (discussed below), a regulatory asset related to the rate reduction bonds of approximately $1.1 billion, and a credit balance of $0.6 billion in balancing account called the Transition Cost Balancing Account (TCBA) which tracks the amount of transition costs that must be recovered. These generation-related regulatory assets decreased by $1.4 billion for the nine months ended September 30, 2000, and decreased $955 million for the nine months ended September 30, 1999.

Certain transition costs can be recovered through a non-bypassable charge to distribution customers after the transition period. These costs include (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, (3) up to $95 million of transition costs to the extent that the recovery of such costs during the transition period was displaced by the recovery of electric industry restructuring implementation costs, and (4) transition costs financed by the rate reduction bonds. Transition costs financed by the issuance of rate reduction bonds will be recovered over the term of the bonds. In addition, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission the nuclear facility. During the rate freeze, the charge for these costs will not increase Utility customers' electric rates. Excluding these exceptions, the Utility will write off any transition costs not recovered during the transition period.

The Utility has been amortizing its transition costs, including most generation-related regulatory assets, over the transition period in conjunction with the available CTC revenues. During the transition period, a reduced rate of return on common equity of 6.77 percent applies to all generation assets, including those generation assets reclassified to regulatory assets. Beginning January 1, 1998, the Utility started collecting these eligible transition costs through the non-bypassable CTC, market valuation of generation assets in excess of book value, and energy sales from the Utility's electric generation facilities prior to market valuation. Further, transition costs are reduced by the amount that contract prices to purchase power from QFs and other providers are lower than the PX price.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition cost recovery and the amount of transition costs requested for recovery. In February 2000, the CPUC approved substantially all non-nuclear transition costs that were amortized during the first six months of 1998. The CPUC currently is reviewing non-nuclear transition costs amortized from July 1, 1998, to June 30, 1999.

Under the electric industry restructuring law, when the Utility has recovered all of its transition costs the conditions for terminating the rate freeze and ending the transition period will have been satisfied. On August 9, 2000, a settlement agreement was filed by the Utility and others with the CPUC regarding the valuation and disposition of the Utility's hydroelectric assets, specifying that the value of those assets for purpose of transition cost calculation is $2.8 billion.

At August 31, 2000, consistent with transition cost recovery procedures adopted by the CPUC, the Utility credited its TCBA by $2.1 billion, the amount by which the value of the hydroelectric generating assets exceeded the aggregate book value of such assets. The Utility also established a separate regulatory asset in the same amount. The accounting entries were based on the value used in the proposed settlement discussed above. Based on the credit made to the TCBA, the Utility would have completed collection of all transition costs that must be collected during the transition period as of August 2000. If the hydroelectric assets were to be sold or valued at a higher amount, the Utility's transition costs would have been recovered as of an earlier date. Testimony taken to date in the CPUC proceeding in which valuation is to be established put the range of market values from $2.4 billion to in excess of $3 billion under operating and market conditions prior to June 2000. On October 16, 2000, the CPUC issued a ruling re-opening the proceeding to obtain more information from parties about market valuation in light of the different market conditions experienced during the summer of 2000. That new testimony is to be submitted in December 2000 with further testimony and evidentiary hearings scheduled for next year. The accounting entries discussed above are subject to later adjustment based on the final valuation of the hydroelectric assets adopted by the CPUC.

Under the electric industry restructuring law, after the Utility recovers its transition costs, the Utility's retail customers assume responsibility for wholesale energy costs. Actual changes in customer rates will not occur until the Utility files for new retail rates and the CPUC authorizes them.

During the transition period, the Utility is required to continue to use the transition period accounting mechanisms, discussed above. This requires that revenues from sales to the PX of Utility-owned generation and generation from QFs and other providers in excess of costs be credited to the TCBA. In addition, the TCBA balance includes a credit for the amount of PX revenues from the Utility's sale of generation from the Diablo Canyon nuclear power plant to the PX that exceed revenues from the fixed Incremental Cost Incentive Price (ICIP). (During 2000, the ICIP is 3.43 cents per kWh.) After taking into account the credit for the hydroelectric assets described above, at September 30, 2000, the Utility's TCBA had a credit balance of approximately $585 million. As mentioned above, the CPUC has issued a ruling indicating that it would reconsider certain of these accounting mechanisms noting that the CPUC has the authority to implement any necessary changes to the electric restructuring accounting provisions and cost recovery consistent with statutory requirements.

Generation Divestiture

In 1998, the Utility sold three fossil-fueled generation plants for $501 million. These three fossil-fueled plants had a combined book value at the time of the sale of $346 million and a combined capacity of 2,645 megawatts (MW).

On April 16, 1999, the Utility sold three other fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and a combined capacity of 3,065 MW.

On May 7, 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and a combined capacity of 1,224 MW.

The gains from the sale of the fossil-fueled generation plants were used to offset other transition costs. Likewise, the loss from the sale of the complex of geothermal generation facilities is being recovered as a transition cost.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

As discussed above, on August 9, 2000, the Utility and a number of interested parties filed an application with the CPUC requesting that the CPUC approve a settlement agreement reached by these parties in the Utility's proceeding to determine the market value of its hydroelectric generation assets. In this settlement agreement, the Utility indicated that it would transfer its hydroelectric generation assets, at a value of $2.8 billion, to an affiliate (referred to herein as PG&E CalHydro) that would not be subject to cost of service regulation by the CPUC.

PG&E CalHydro would hold and operate the assets, subject to a 40-year revenue sharing agreement (RSA) between PG&E CalHydro and the Utility. Under the RSA, PG&E CalHydro would be allowed to recover an authorized inflation-indexed operations and maintenance allowance, certain other expenses including an allowance for capital additions, and a return on capital investment. The return on equity (ROE) initially would be set at 12.50 percent and would be subject to an indexed adjustment trigger. Under the RSA, 90 percent of the after-tax earnings received in excess of the agreed-upon costs (including the target ROE) would be returned to the Utility to be used as a credit against current costs charged to the Utility's distribution ratepayers. If market revenues were insufficient to recover the agreed-upon costs of operating the hydroelectric facilities (including the target ROE) over a multi-year period, 90 percent of the revenue shortfalls would be charged to the Utility to be recovered from distribution customers.

The RSA would become effective on the date that the CPUC order approving the settlement and the RSA becomes final and non-appealable, subject to termination by either the Utility or PG&E CalHydro in certain circumstances. The CPUC may accept the settlement or reject it, suggest changes to it, or adopt a different valuation approach. In addition, the transfer of the assets from the Utility to PG&E CalHydro will require the approval of the FERC.

At September 30, 2000, the book value of the Utility's net investment in hydroelectric generation assets was approximately $700 million. The above settlement, if approved, would result in a pre-tax charge of $2.1 billion. If the value of the hydroelectric generation assets is determined by any method other than a sale of the assets to an unrelated third party, a material charge to Utility earnings could result. The timing and nature of any such charge is dependent upon the valuation method and procedure adopted, and the method of implementation. The CPUC is not likely to consider the Utility's proposed settlement until next year, and it is uncertain at this time whether the settlement will be approved, modified or rejected, or withdrawn.

Post-Transition Period

The CPUC has established the Purchased Electric Commodity Account (PECA) for the Utility to track energy costs after the rate freeze and transition period end. In June 2000, the CPUC issued a decision in the second phase of the Utility's post-transition period electric ratemaking proceeding. Among other things, the CPUC determined that the PECA would reflect a pass-through of energy costs, possibly subject to after-the-fact reasonableness reviews.

After the rate freeze ends, Diablo Canyon will be operated as a competitive generator of electricity with revenues generated from prevailing market rates. During the rate freeze, Diablo Canyon's operating costs have been recovered through the incremental cost incentive price (ICIP) mechanism. The ICIP, which has been in place since January 1, 1997, is a performance-based mechanism that establishes a rate per kWh generated by the facility. The ICIP prices for 1999, 2000, and 2001 are 3.37 cents per kWh, 3.43 cents per kWh, and 3.49 cents per kWh, respectively.

As required by a prior CPUC decision on June 30, 2000, the Utility filed an application with the CPUC requesting approval of its proposal for sharing with ratepayers 50 percent of the post-rate freeze net benefits of operating Diablo Canyon. The net benefit sharing methodology proposed in the Utility's application would be effective at the end of the current electric rate freeze for the Utility's customers and would continue for as long as the Utility owned Diablo Canyon. Under the proposal, the Utility would share the net benefits of operating Diablo Canyon based on the audited profits from operations, determined consistent with the prior CPUC decisions. If Diablo Canyon experiences losses, such losses would be accrued and netted against profits in the calculation of the net benefits in subsequent periods (or against profits in prior periods if subsequent profits are insufficient to offset such losses). Any changes to the net sharing methodology must be approved by the CPUC.

Future Competition

Opening California's electric generation to competition has raised certain interest in introducing further competition in the electric industry. The CPUC has opened a rulemaking proceeding to examine the various issues associated with distributed generation. Distributed generation enables the siting of electric generation technologies in close proximity to electric demand, and raises issues about stranded costs (both within distribution and transmission systems), interconnection charges, and cost allocation. The CPUC staff has issued a report identifying options for possible CPUC consideration regarding the additional unbundling of the electric distribution function and evaluate the investor-owned utilities' role of default provider of electricity.

It is too early to predict what may come of these matters. PG&E Corporation is unable to predict when these issues will be addressed by the CPUC or whether the results will have any impact on the Utility.

NOTE 3: RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The following table is a summary of the contract or notional amounts and maturities of PG&E Corporation's contracts used for non-hedging activities related to commodity risk management as of September 30, 2000 and 1999. Short and long positions pertaining to derivative contracts used for hedging activities as of September 30, 2000 and 1999, are immaterial.

Natural Gas, Electricity, and Natural Gas Liquids Contracts	Purchase (Long)	Sale (Short)	Maximum Term in Years
(billions of MMBtu equivalents (1))			
Non-Hedging Activities - September 30, 2000			
Swaps	2.07	1.91	6
Options	0.45	0.34	8
Futures	0.08	0.12	3
Forward Contracts	3.00	2.03	22
Non-Hedging Activities - September 30, 1999			
Swaps	3.18	3.14	7
Options	1.13	0.99	5
Futures	0.29	0.30	2
Forward Contracts	1.95	1.59	12

(1) One MMBtu is equal to one million British thermal units. PG&E Corporation's electric power contracts, measured in megawatts, were converted to MMBtu equivalents using a conversion factor of 10 MMBtu's per 1 megawatt-hour. PG&E Corporation's natural gas liquids contracts were converted to MMBtu equivalents using an appropriate conversion factor for each type of natural gas liquids product.

Volumes shown for swaps represent notional volumes that are used to calculate amounts due under the agreements and do not represent volumes exchanged. Moreover, notional amounts are indicative only of the volume of activity and are not a measure of market risk.

PG&E Corporation's net gains (losses) on swaps, options, futures, and forward contracts held during the three and nine months ended September 30, 2000 and 1999, are as follows:

	Three months ended September 30, 2000	Three months ended September 30, 1999	Nine months ended September 30, 2000	Nine months ended September 30, 1999
(in millions)	$ 50	$ (7)	$ 129	$ (5)
Options	8	30	70	(5)
Futures	(31)	(3)	(55)	(23)
Forward contras	(4)	(35)	(57)	60

Net gain (loss)	$23	$ (15)	$ 87	$ 27

The following table discloses the estimated fair values of risk management assets and liabilities as of September 30, 2000, and December 31, 1999. The ending and average fair values and associated carrying amounts of derivative contracts used for hedging purposes are not material as of September 30, 2000, and December 31, 1999.

	Average Fair Value	Ending Fair Value
(in millions)		
Non-hedging activities - September 30, 2000		
Assets		
Swaps	$ 136	$ 153
Options	102	107
Futures	26	21
Forward Contracts	820	841
Total	$ 1,084	$ 1,122
Noncurrent portion		$ 346
Current portion		$ 776
Liabilities		
Swaps	$ 91	$ 53
Options	48	35
Futures	45	70
Forward Contracts	758	801
Total	$ 942	$ 959
Noncurrent portion		$ 313
Current portion		$ 646
Non-hedging activities - December 31, 1999		
Assets		
Swaps	$ 643	$ 244
Options	106	92
Futures	175	47
Forward Contracts	667	596
Total	$ 1,591	$ 979
Noncurrent portion		$ 372
Current portion		$ 607
Liabilities		
Swaps	$ 592	$ 218
Options	109	81
Futures	201	67
Forward Contracts	561	456
Total	$ 1,463	$ 822
Noncurrent portion		$ 247

Current portion	$ 575

PG&E Corporation, primarily through its subsidiaries, engages in risk management activities for both non-hedging and hedging purposes. Non-hedging activities are conducted principally through its unregulated subsidiary, PG&E Energy Trading (PG&E ET). In compliance with regulatory requirements, the Utility manages risk independently from the activities in PG&E Corporation's unregulated businesses. The Utility primarily engages in hedging activities which were immaterial for the three- and nine-month periods ended September 30, 2000 and 1999.

In valuing its electric power, natural gas, and natural gas liquid portfolios, PG&E Corporation considers a number of market risks and estimated costs, and continuously monitors the valuation of identified risks and adjusts them based on present market conditions. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided herein are not necessarily indicative of the amounts that PG&E Corporation could realize in the current market.

Generally, exchange-traded futures contracts require deposit of margin cash, the amount of which is subject to change based on market movement and in accordance with exchange rules. Margin requirements for over-the-counter financial instruments are specified by the particular instrument and often do not require margin cash and are settled monthly. Both exchange-traded and over-the-counter options contracts require payment/receipt of an option premium at the inception of the contract. Margin cash for commodities futures and cash on deposit with counterparties was $63.6 million at September 30, 2000.

The credit exposure of the five largest counterparties comprised approximately $548 million of the total credit exposure associated with financial instruments used to manage price risk. Counterparties considered to be investment grade or higher comprise 86 percent of the total credit exposure.

NOTE 4: UTILITY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF TRUST HOLDING SOLELY UTILITY SUBORDINATED DEBENTURES

The Utility, through its wholly owned subsidiary, PG&E Capital I (Trust), has outstanding 12 million shares of 7.90 percent cumulative quarterly income preferred securities (QUIPS), with an aggregate liquidation value of $300 million. Concurrent with the issuance of the QUIPS, the Trust issued to the Utility 371,135 shares of common securities with an aggregate liquidation value of approximately $9 million. The only assets of the Trust are deferrable interest subordinated debentures issued by the Utility with a face value of approximately $309 million, an interest rate of 7.90 percent, and a maturity date of 2025.

NOTE 5: DIVESTITURES

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E Energy Services (PG&E ES), its wholly owned subsidiary, through a sale. In December 1999, the disposal was accounted for as a discontinued operation and PG&E Corporation's investment in PG&E ES was written down to its then estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the anticipated date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million. During the second quarter of

2000, PG&E National Energy Group finalized a transaction related to the disposal of PG&E ES commodity trading assets for $20 million, plus net working capital of approximately $65 million, for a total of $85 million. In addition, the sale of the Value-Added-Services business and various other assets was completed on July 21, 2000, for a total consideration of $18 million. Both of these sales have working capital true-ups which will not be finalized until 2001. For the three- and nine-months ended September 30, 2000, an additional estimated loss of $19 million (or $0.05 per share), net of income taxes of $13 million was recorded. The PG&E ES business segment generated net losses from operations of $34 million, net of income taxes of $26 million for the nine-month period ended September 30, 1999.

On January 27, 2000, PG&E National Energy Group signed a definitive agreement with El Paso Field Services Company (El Paso) providing for the sale to El Paso, a subsidiary of El Paso Energy Corporation, of the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. (collectively, PG&E GT Texas). The consideration to be received by PG&E National Energy Group includes $279 million in cash, subject to adjustments for working capital, debt repayment, and certain other items, as well as, the assumption by El Paso of liabilities associated with PG&E GT Texas and debt having a book value of $566 million.

In 1999, PG&E Corporation recognized a charge against earnings of $890 million after-tax as follows: (1) an $819 million write-down of net property, plant, and equipment, (2) the elimination of the unamortized portion of goodwill, in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

Proceeds from the sale will be used to retire short-term debt associated with PG&E GT Texas' operations and for other corporate purposes. Closing of the sale, which is expected in the fourth quarter of 2000, is subject to approval under the Hart-Scott-Rodino Act.

The sale of PG&E GT Texas represents disposal of the PG&E GT Texas business segment and a portion of the PG&E ET business segment. PG&E GT Texas' total assets and liabilities, including the charge noted above, included in the PG&E Corporation Condensed Consolidated Balance Sheet at September 30, 2000, and December 31, 1999, are as follows:

(in millions)	September 30, 2000	December 31, 1999
Assets		
Current assets	$ 266	$ 229
Noncurrent assets	979	988
Total Assets	1,245	1,217
Liabilities		
Current liabilities	589	448
Noncurrent liabilities	504	624
Total Liabilities	1,093	1,072
Net Assets	$ 152	$ 145

NOTE 6: COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

The Utility has insurance coverage for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, the Utility may be subject to maximum retrospective assessments of $12 million (property damage) and $4 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection which provides an additional $9.3 billion in coverage, which is mandated by federal legislation. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Environmental Matters

Companies within the PG&E Corporation group may be required to pay for environmental remediation at sites where it has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used for the storage or disposal 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.

Utility:

The Utility records a liability when site assessments indicate remediation is probable and a range of reasonably likely clean-up costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The remediation costs also reflect (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) 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 lower end of this range.

The cost of the hazardous substance remediation ultimately undertaken is difficult to estimate. A change in estimate may occur in the near term due to uncertainty concerning responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives.

At September 30, 2000, the Utility expects to spend $307 million for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants. The Utility had an accrued liability of $279 million and $271 million at September 30, 2000, and December 31, 1999, respectively, representing the discounted value of these costs.

Of the $279 million accrued liability discussed above, the Utility has recovered $154 million through rates, including $39 million through depreciation, and expects to recover another $96 million in future rates. Additionally, the Utility is mitigating its costs by obtaining recovery of its costs from insurance carriers and from other third parties as appropriate.

Environmental remediation at identified sites may be as much as $480 million if, among other things, other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated. The Utility estimated this upper limit of the range of costs using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for clean-up costs at additional sites or outcomes change.

Further, as discussed in the "Generation Divestiture" section of Note 2, the Utility will retain the pre-closing remediation liability associated with divested generation facilities.

The Utility believes the ultimate outcome of these matters will not have a material impact on the Utility's financial position or results of operations.

PG&E National Energy Group:

USGen New England (USGenNE), a subsidiary of the PG&E National Energy Group has a 760 MW coal-fired power plant in Salem, Massachusetts and a 1,586 MW coal-fired in Somerset, Massachusetts (Brayton Point power plant). The Commonwealth of Massachusetts is considering the adoption of more stringent reductions in air emissions from electric generating facilities which is expected to impact those plants. USGen NE, has proposed an emission reduction plan that may include modernization of the plant in Salem and the use of advanced technologies for emissions removal. USGenNE is also studying various advanced technologies for emissions removal for the Brayton Point power plant.

On April 18, 2000, the Conservation Law Foundation (CLF) served various PG&E Gen affiliates, including USGenNE, a notice of its intent to file suit under the citizen suit provision of the Resource Conservation Recovery Act. On September 15, 2000, USGenNE entered into a series of agreements with the Massachusetts Department of Environmental Protection and CLF that address and resolve the potential claims CLF identified in its April 18, 2000 letter. The agreements require, among other things, that USGenNE alter its existing water treatment facilities at both the Salem Harbor and Brayton Point power plants by replacing certain unlined treatment basins; submit and implement a plan for the closure of such basins; and perform certain environmental testing at the facilities. The agreements are incorporated in a complaint, answer and proposed judgment to which USGenNE and CLF agreed. The complaint, answer and proposed judgment have been filed in federal court. On October 19, 2000, the court entered the consent decree in the docket.

In May 2000, USGenNE received a request for information pursuant to Section 114 of the Clean Air Act from the U.S. Environmental Protection Agency (EPA) seeking detailed operating and maintenance history for the Salem Harbor and Brayton Point power plants. The Company believes that this request for information is part of the EPA's industry-wide investigation of coal-fired electric power generators to determine compliance with environmental requirements under the Clean Air Act associated with repairs, maintenance, modifications, and operational changes made to coal-fired facilities over the years. If the EPA were to find that there were physical changes made in the past that were undertaken without first receiving the required permits under the Clean Air Act, then penalties may be imposed and further emission reductions might be necessary at these plants. PG&E Corporation believes the ultimate outcome of these matters will not have a material impact on its financial position or results of operations.

Legal Matters

Chromium Litigation:

Several civil suits are pending against the Utility in California state court. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Currently, there are claims pending on behalf of approximately 1,000 individuals.

The Utility is responding to the suits and asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations or exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

PG&E Corporation believes that the ultimate outcome of these matters will not have a material adverse impact on its or the Utility's financial position or results of operations.

Texas Franchise Fee Litigation:

In connection with PG&E Corporation's acquisition of Valero Energy Corporation, now known as PG&E Gas Transmission, Texas Corporation (PG&E GTT), PG&E GTT succeeded to the litigation described below.

PG&E GTT and various of its affiliates are defendants in at least two class action suits and five separate suits filed by various Texas cities. Generally, these cities allege, among other things, that (1) owners or operators of pipelines occupied city property and conducted pipeline operations without the cities' consent and without compensating the cities, and (2) the gas marketers failed to pay the cities for accessing and utilizing the pipelines located in the cities to flow gas under city streets. Plaintiffs also allege various other claims against the defendants for failure to secure the cities' consent. Damages are not quantified.

In 1998, a jury trial was held in the separate suit brought by the City of Edinburg (the City). This suit involved, among other things, a particular franchise agreement entered into by a former subsidiary of PG&E GTT (now owned by Southern Union Gas Company (SU)) and the City and certain conduct of the defendants. On December 1, 1998, based on the jury verdict, the court entered a judgment in the City's favor, and awarded damages of $5.3 million, and attorneys' fees of up to $3.5 million plus interest. The court found that various PG&E GTT and SU defendants were jointly and severally liable for $3.3 million of the damages and all the attorneys' fees. Certain PG&E GTT subsidiaries were found solely liable for $1.4 million of the damages. The court did not clearly indicate the extent to which the PG&E GTT defendants could be found liable for the remaining damages. The PG&E GTT defendants are in the process of appealing the judgment.

In one of the class actions, opt-out notices were sent to approximately 159 Texas cities as potential class members and fewer than 20 cities opted out by the deadline in 1997. In November 1999, the court dismissed from the class 42 cities because it determined there was no pipeline presence and no past or present sales activity, leaving 106 cities in the class. Certain of the 106 class members have elected to opt out of the settlement in 2000. In July 2000, the defendants effectuated a settlement with approximately 70 percent of the class members pursuant to which the defendants paid an aggregate of $6.3 million (inclusive of attorney's fees and expenses) in exchange for a comprehensive release from past liabilities and a license to use city rights-of-way for 25 years. In September 2000, the court approved a settlement as to the remaining 21 plaintiffs in this case (who are also class members of another pending class action lawsuit involving a third party). The defendants paid approximately $4 million to these plaintiffs in exchange for a comprehensive release from past liabilities and a license to use city rights-of-way for 25 years. Settlement discussions are continuing with the city of Corpus Christi and other Texas cities.

Efforts also continue in attempts to reach arrangements with other large Texas cities, including San Antonio, Austin and Brownsville, regarding potential liability of PG&E corporation-related Texas entities for the possible unauthorized presence of pipe within city rights-of-way.

PG&E Corporation believes that the ultimate outcome of these matters will not have a material adverse impact on its financial position or its results of operations. In January 2000, PG&E National Energy Group signed a definitive agreement to sell the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. The buyer will assume all liabilities associated with the cases described above.

Recorded Liability for Legal Matters:

In accordance with Statement of Financial Accounting Standards (SFAS) No. 5, PG&E Corporation makes a provision for a liability when both it is 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, rulings, advice of legal counsel, and other information and events pertaining to a particular case. The following table reflects the current year's activity to the recorded liability for legal matters:

(in millions)	PG&E Corporation	Utility
Beginning balance, January 1, 2000	$ 126	$ 70
Provisions for liabilities	27	27
Payments	(27)	(13)
Ending balance, September 30, 2000	$ 126	$ 84

NOTE 7: SEGMENT INFORMATION

PG&E Corporation has identified four reportable operating segments. The Utility is one reportable operating segment and the other three are part of PG&E National Energy Group. These four reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. PG&E Corporation's reportable segments are described below.

Utility: PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company, provides natural gas and electric service to one of every 20 Americans.

PG&E National Energy Group: PG&E National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and in Texas, through various subsidiaries of PG&E Corporation (collectively, PG&E Gas Transmission or PG&E GT); and purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the other PG&E National Energy Group non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading - Gas Corporation, PG&E Energy Trading - Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET). PG&E Corporation has entered into an agreement to sell its Texas natural gas and natural gas liquids business.

Segment information for the three and nine months ended September 30, 2000 and 1999, respectively, was as follows:

	Utility	PG&E National Energy Group					
			PG&E GT			Elimi-nations &	
		PG&EGen	NW	Texas	PG&E ET	Other (1)	Total
(in millions)							
For the three months ended September 30, 2000							
Operating revenues	$ 2,519	$ 287	$ 52	$ 241	$ 4,406	$ (1)	$ 7,504
Intersegment revenues	4	3	12	17	371	(407)	-
Total operating revenues	2,523	290	64	258	4,777	(408)	7,504
Income from continuing operations	211	16	16	-	1	-	244
For the three months ended September 30, 1999							
Operating revenues	$ 2,584	$ 273	$ 42	$ 161	$ 3,151	$ 6	$ 6,217
Intersegment revenues	3	2	14	16	339	(374)	-
Total operating revenues	2,587	275	56	177	3,490	(368)	6,217
Income from continuing operations	179	21	18	(7)	(17)	3	197
For the nine months ended September 30, 2000							
Operating revenues	$ 7,026	$ 877	$ 140	$ 661	$ 9,457	$ (11)	$18,150

Intersegment revenues	11	6	37	46	1,036	(1,136)	-
Total operating revenues	7,037	883	177	707	10,493	(1,147)	18,150
Income from continuing operations	655	70	43	-	14	(10)	772
Total assets at September 30, 2000	24,183	4,198	1,129	1,245	2,936	200	33,891
For the nine months ended September 30, 1999							
Operating revenues	$ 6,898	$ 814	$ 127	$ 871	$ 7,314	$ 1	$16,025
Intersegment revenues	7	4	39	99	831	(980)	-
Total operating revenues	6,905	818	166	970	8,145	(979)	16,025
Income from continuing operations	498	77	46	(39)	(19)	(3)	560
Total assets at September 30, 1999	21,740	3,858	1,162	2,548	2,195	(17)	31,486

(1) Net income on intercompany positions recognized by segments using mark-to-market accounting is eliminated. Intercompany transactions are also eliminated.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), provides natural gas and electric service to one of every 20 Americans. PG&E National Energy Group provides energy products and services throughout North America.

PG&E National Energy Group businesses develop, construct, operate, own, and manage independent power generation facilities that serve wholesale and industrial customers through PG&E Generating Company, LLC (and its affiliates (collectively, PG&E Gen); own and operate natural gas pipelines, natural gas storage facilities, and natural gas processing plants, primarily in the Pacific Northwest and in Texas (collectively, PG&E Gas Transmission or PG&E GT); and purchase and sell energy commodities and provide risk management services to customers in major North American markets, including the other PG&E National Energy Group non-utility businesses, unaffiliated utilities, marketers, municipalities, and large end-use customers through PG&E Energy Trading-Gas Corporation, PG&E Energy Trading-Power, L.P., and their affiliates (collectively, PG&E Energy Trading or PG&E ET). PG&E Corporation has entered into an agreement to sell its Texas natural gas and natural gas liquids business.

This is a combined Quarterly Report on Form 10-Q of PG&E Corporation and Pacific Gas and Electric Company. It includes separate consolidated financial statements for each entity. The condensed consolidated financial statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's wholly owned and controlled subsidiaries. The condensed consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned and controlled subsidiaries. This Management's Discussion and Analysis (MD&A) should be read in conjunction with the condensed consolidated financial statements included herein. Further, this quarterly report should be read in conjunction with the Corporation's and the Utility's Consolidated Financial Statements and Notes to Consolidated Financial Statements incorporated by reference in their combined 1999 Annual Report on Form 10-K.

This combined Quarterly Report on Form 10-Q, including this MD&A, contains forward-looking statements about the future that are necessarily subject to various risks and uncertainties. These statements are based on current expectations and assumptions which management believes are reasonable and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

Factors that could cause future results to differ materially from those expressed in or implied by the forward-looking statements or historical results include:

- legislative or regulatory changes, including the pace and extent of the ongoing restructuring of the electric and natural gas industries across the United States;

- the amount and method of recovery from customers of the under-collected electric procurement costs recorded in the Utility's TRA;

- what regulatory, judicial, and legislative actions may be taken to mitigate the higher power prices;

- future sales levels and economic conditions;

- the method and timing of disposition and valuation of the Utility's hydroelectric generation assets;

- the timing of the completion of the Utility's transition cost recovery and the consequent end of the current electric rate freeze in California.

- any changes in the amount of transition costs the Utility is allowed to collect from its customers;

- future operating performance at the Diablo Canyon Nuclear Power Plant (Diablo Canyon);

- the method adopted by the California Public Utilities Commission (CPUC) for sharing the net benefits of operating Diablo Canyon with ratepayers and the timing of the implementation of the adopted method;

- the extent of anticipated growth of transmission and distribution services in the Utility's service territory;

- future market prices for electricity and future fuel prices which, in part, are influenced by future weather conditions and the availability of hydroelectric power;

- the success of management's strategies to maximize shareholder value in PG&E National Energy Group, which may include acquisitions or dispositions of assets, or investments in emerging companies or new businesses;

- the extent to which our current or planned generation development projects are completed and the pace and cost of such completion;

- generating capacity expansion and retirements by others;

- the outcome of the Utility's various regulatory proceedings, including the proceeding to determine the value of the Utility's hydroelectric generation assets, the electric transmission rate case applications, post-transition period ratemaking proceedings, the 2001 attrition rate adjustment request, the cost of capital application, and the 2002 General Rate Case;

- fluctuations in commodity gas, natural gas liquids, and electric prices and our ability to successfully manage such price fluctuations;

- the pace and extent of competition in the California generation market and its impact on the Utility's costs and resulting collection of transition costs;

- the effect of compliance with existing and future environmental laws, regulations, and policies, the cost of which could be significant; and

- the outcome of pending litigation.

As the ultimate impact of these and other factors is uncertain, these and other factors may cause future earnings to differ materially from results or outcomes we currently seek or expect.

In this MD&A, we first discuss our competitive and regulatory environment. We then discuss earnings and changes in our results of operations for the quarters ended September 30, 2000 and 1999. Finally, we discuss liquidity and financial resources, various uncertainties that could affect future earnings, and our risk management activities. Our MD&A applies to both PG&E Corporation and the Utility.

THE CALIFORNIA ELECTRIC INDUSTRY

In 1998, California became one of the first states in the country to implement electric industry restructuring and establish a market framework for electric generation. Today, most Californians may continue to purchase their electricity from investor-owned utilities such as Pacific Gas and Electric Company, or they may choose to purchase electricity from alternative generation providers (such as independent power generators and retail electricity suppliers such as marketers, brokers, and aggregators). For those customers who have not chosen an alternative generation provider, investor-owned utilities, such as the Utility, continue to be the generation providers. Investor-owned utilities continue to provide distribution services to substantially all customers within their service territories, including customers who choose an alternative generation provider.

An Independent System Operator (ISO) and a Power Exchange (PX) operate in California. The PX provides a process to establish market-clearing prices for electricity in the markets operated by the PX. The ISO schedules delivery of electricity for all market participants and operates the real-time and ancillary services markets for electricity. (Ancillary services are needed to maintain the reliability of the electric grid.) The Utility continues to own and maintain its transmission system, but the ISO controls the operation of the system. During the transition period, the Utility is required to bid or schedule into the PX and ISO markets all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators. On August 3, 2000, the California Public Utilities Commission (CPUC) authorized the Utility to purchase energy and ancillary services and capacity products for retail customers in wholesale markets outside the PX and to set up memorandum accounts to track related costs. Such transactions are confined to previous limits established for forward market purchases and must expire before December 31, 2005.

Competitive Market Framework

Beginning in June 2000, the Utility has experienced unanticipated and massive increases (above the generation-related costs component embedded in frozen rates) in the wholesale costs of the electric energy that is purchased from the PX on behalf of its retail customers. The average price that the PX charged the Utility for electric power in the months of June, July, August, and September 2000, was approximately 16.3 cents per kilowatt-hour (kWh), 11.0 cents per kWh, 18.7 cents per kWh and 14.0 cents per kWh, respectively, compared to 3.0, 3.9, 4.1 and 4.0 cents per kWh for the same months in 1999. The generation-related cost component that is embedded in frozen rates and available for payment of wholesale electric power costs during those same periods was approximately 5.4 cents per kWh. The forward curve for power prices in the California market suggests that these costs may remain well above the embedded cost component of frozen rates through the end of this year and beyond next summer unless significant changes occur in the wholesale power market.

As a result, the Utility has incurred and continues to incur expenses representing the excess of power purchase costs above the generation component embedded in frozen rates. Such expenses are deferred to a regulatory balancing account called the Transition Revenue Account (TRA). The TRA balance as of September 30, 2000 was approximately $2.9 billion. The TRA balance does not reflect the Utility's revenues from (1) sales of energy from retained generation facilities to the PX in excess of authorized costs or (2) the amount by which the PX prices exceed the purchase price contained in the Utility's long-term contracts to purchase energy from Qualifying Facilities (QF) and other power providers. Approximately half of the Utility's suppliers under QF contracts have elected to receive PX based prices for energy in addition to contractual capacity payments. The Utility expects that most remaining QF generators will elect to receive PX prices for their energy payments by summer 2001. The Utility pays these suppliers directly, rather than through the PX, but receives billing credits for energy delivered to the PX from QFs.

A prior CPUC decision would prohibit the Utility from collecting after the transition period certain electric costs incurred during the transition period but not recovered from frozen rates during that period, including TRA under-collections. The CPUC decision also would prohibit offsetting these specific under-collected balances against over-collected transition costs. The Utility is seeking judicial review by the California Supreme Court. The Utility's petition is pending.

On October 4, 2000, the Utility and Southern California Edison Company filed separate emergency petitions with the CPUC to rescind and modify as necessary prior decisions prohibiting utilities from carrying over costs incurred during the rate freeze to the post-rate freeze period. The utilities noted that many parties have acknowledged that the wholesale electric power market is not workably competitive and that the significant increases in prices were not considered in the CPUC's original rulings. On October 17, 2000, the administrative law judge (ALJ) and the CPUC commissioner assigned to review the emergency petition issued a joint ruling indicating that they would reconsider the accounting mechanisms established in prior CPUC decisions and adopt a schedule that permits a decision by the end of the year.

In response to the above ruling, the Utility filed its proposals requesting that the CPUC modify its prior decisions to authorize the utilities to transfer any unrecovered balance in the TRA as of the end of the rate freeze into a new balancing account, and authorize recovery of the balance in that new account over a period not to exceed four years, subject to a rate stabilization plan to be addressed in a second phase of the proceeding. The Utility asked the CPUC to adopt an expedited procedural schedule in a second phase that would, not later than March 31, 2001, resolve the following issues: (1) implementation of when and how the rate freeze is to be ended; (2) adoption of post rate freeze tariffs and rates; (3) approval of the rate stabilization plan; and (4) adoption of the retail rate components for recovery of the new balancing account. The Utility indicated that it will submit its detailed proposals on the rate stabilization plan and tariffs by November 15, 2000.

At the prehearing conference held on October 27, 2000, the ALJ indicated that the scope of the proceeding was solely to consider accounting mechanisms to reduce the TRA under-collections and that the Utility's proposals for interim relief were broader than contemplated in the October 17th ruling, were not consistent with the CPUC's prior decisions precluding carryover of under-collected TRA costs, and would not be considered in the proceeding before the end of the year. However, the ALJ indicated that the CPUC would consider proposals made by The Utility Reform Network (TURN), a consumer group, to transfer TRA under-collections to the TCBA. TURN's proposals would treat under-collected electric procurement costs for accounting purposes as if such costs were unrecovered transition costs, the likely effect of which would be to delay the completion of transition cost recovery by the Utility as well as delay the end of the rate freeze. If TURN's proposal were adopted, the Utility would have to write-off any unrecovered transition costs remaining in the TCBA if such costs were not probable of recovery. The ALJ ordered the parties to respond to the utilities' emergency petitions and to TURN's proposal by November 9, 2000.

The Utility reviews on an ongoing basis the facts and circumstances relating to the TRA under-collections. The Utility currently believes recovery of the TRA under-collections is probable. TRA under-collections are recorded as a regulatory asset on the balance sheet rather than being charged to earnings because it is probable that these under-collections will be recovered through the ratemaking process. However, ultimate recovery is dependent upon the favorable outcome of the regulatory actions described above, as well as upon other factors such as future market prices of electricity and future fuel prices that, in part, are influenced by sales level, and economic conditions, about which there can be no certainty. If regulatory or judicial relief is not forthcoming, and if the Utility determines that its uncollected wholesale power purchase costs are not probable of recovery, then the Utility would be required to write off the unrecoverable portion as a charge against earnings. In addition, the Utility would be unable to continue deferring these costs incurred during the transition period and such expenses would reduce the Utility's future earnings accordingly. With respect to wholesale power purchase costs incurred after the end of the transition period and prior to any adjustment in rates, the Utility may be able to defer these costs if it determines that they are probable of recovery.

The Utility is actively exploring ways to reduce its exposure to the higher power purchase costs and its corresponding TRA balance, including working with interested parties to address power market dysfunction before appropriate regulatory bodies and hedging a portion of its open procurement position against higher purchase power costs through forward purchases. The CPUC only recently authorized the Utility to enter into bilateral power purchase contracts. In October 2000, the Utility entered into bilateral power purchase contracts with several suppliers.

On October 16, 2000, the Utility joined with Southern California Edison and TURN in filing a petition with the Federal Energy Regulatory Commission (FERC) requesting that the FERC (1) immediately find the California wholesale electricity market to be not workably competitive and the resulting prices to be unjust and unreasonable; (2) immediately impose a cap on the price for energy and ancillary services; and (3) institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions, and responsibility for refunds. However, the reduced price cap requested, even if approved, would still be above the approximate 5.4 cents per kWh embedded in frozen rates for the payment of the Utility's wholesale power purchase costs. Also, on October 20, 2000, the ISO filed a market stabilization plan with the FERC requesting the FERC to impose a price cap of $100 per megawatt-hour (Mwh) (10 cents per kWh) for generators who do not enter into contracts to supply 70 percent of their supply to serve California customers. There are certain other exemptions to the $100 price cap. The existing $250 price cap per Mwh hour (25 cents per kWh) would apply to generators who are exempt from the $100 per Mwh hour price cap. The ISO also has recommended that buyers (utilities) be required to contract for 85 percent of their customer requirements for power in advance of when the power is needed. Further, the ISO has adopted additional load based price caps for the real-time and ancillary service markets which would range between $65 and $250 per Mwh. These price caps would begin as soon as November 3, 2000, and remain in place until real-time and ancillary service markets have demonstrated that they are workably competitive under a variety of load conditions.

A Joint Resolution of the California legislature called on the CPUC to initiate an investigation to review the impact of the current electricity crisis on consumers and California investor-owned utilities with emphasis on the options for correcting the electricity market, methods to eliminate price volatility for consumers, and importantly, methods for cost recovery and cost allocation. In response, the CPUC issued an order on September 7, 2000 expanding an existing investigation into the wholesale electric market and the associated impact on electric rates to include the issues identified by the legislature.

For the three and nine months ended September 30, 2000 and 1999, the cost of electric energy for the Utility, reflected on the Condensed Consolidated Income Statement, is comprised of the cost of fuel for electric generation and QF purchases, the cost of PX purchases, and ancillary services charged by the ISO, net of sales to the PX, as follows:

	Three months ended September 30, 2000	Three months ended September 30, 1999	Nine months ended September 30, 2000	Nine months ended September 30, 1999
(in millions)				
Cost of fuel for electric generation and QF purchases	$ 592	$ 409	$ 1,203	$ 1,178
Cost of purchases from the PX and ISO	2,132	554	3,492	1,101

Proceeds from sales to the PX	(668)	(217)	(1,151)	(598)
Total Utility cost of electric energy	$ 2,056	$ 746	$ 3,544	$ 1,681

Transition Period, Rate Freeze, and Rate Reduction

California's electric industry restructuring established a transition period during which electric rates remain frozen at 1996 levels (with the exception that, on January 1, 1998, rates for small commercial and residential customers were reduced by 10 percent and remain frozen at this reduced level) and investor-owned utilities may recover their transition costs. Transition costs are generation-related costs that prove to be uneconomic under the new industry structure. The transition period ends the earlier of December 31, 2001, or when the particular utility has recovered its eligible transition costs.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion (the expected revenue reduction from the rate decrease) of its transition costs with the proceeds from the rate reduction bonds. The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period. During the rate freeze, the rate reduction bond debt service will not increase the Utility customers' electric rates. If the transition period ends before December 31, 2001, the Utility may be obligated to return a portion of the economic benefits of the transaction to customers. The timing of any such return and the exact amount of such portion, if any, have not yet been determined.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, nuclear decommissioning, rate reduction bond debt service, and the cost of procuring electricity for the Utility's retail customers. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the competition transition charge (CTC), which recovers the transition costs. These CTC revenues are being recovered from all Utility distribution customers and are subject to seasonal fluctuations in the Utility's sales volumes, fluctuating PX energy prices, and certain other factors. The CTC is collected regardless of the customer's choice of electricity supplier (i.e., the CTC is non-bypassable).

Transition Cost Recovery

Although most transition costs must be recovered during the transition period, certain transition costs can be recovered after the transition period. Except for the transition costs discussed below, at the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues.

Transition costs consist of (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and that were included in customers' rates on December 20, 1995) and future sunk costs, such as costs related to plant removal, (2) costs associated with long-term contracts to purchase power at above-market prices from qualifying facilities and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods, to be included in rates in subsequent periods.)

Above-market sunk costs result when the book value of a facility exceeds its market value. Conversely, below-market sunk costs result when the market value of a facility exceeds its book value. The total amount of generation facility costs to be included as transition costs is based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. Revenues generated from the Utility's sales to the PX and ISO that exceed authorized costs are also used to offset transition costs.

For nuclear transition costs, revenues provided for transition cost recovery are based on the accelerated recovery of the investment in Diablo Canyon Nuclear Power Plant (Diablo Canyon) over a five-year period ending December 31, 2001.

Costs associated with the Utility's long-term contracts to purchase electric power are included as transition costs. Regulation required the Utility to enter into long-term agreements with non-utility generators to purchase electric power at fixed prices. Prices fixed under these contracts have generally been above prices for power in wholesale markets. Over the remaining life of these contracts, the Utility estimates that it will purchase 299 million MWh of electric power. The contracts expire at various dates through 2028. To the extent that the individual contract prices are above the market price, the Utility is collecting the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. To the extent that the contracted prices are below the market price, the Utility is using the savings to offset other transition costs during the transition period.

The total costs under long-term contracts are based on several variables, including the capacity factors of the related generating facilities and future market prices for electricity. For the nine months ended September 30, 2000 and 1999, the average price paid under the Utility's long-term contracts for electricity was 7.8 cents and 6.4 cents per kWh, respectively.

At September 30, 2000, and December 31, 1999, the Utility's net generation-related regulatory assets (excluding the TRA) totaled $2.6 billion and $4.0 billion, respectively. Included in the generation-related regulatory assets at September 30, 2000, is $2.1 billion associated with the valuation of the Utility's hydroelectric generation facilities (discussed below), a regulatory asset related to the rate reduction bonds of approximately $1.1 billion, and a credit balance of $0.6 billion in balancing account called the Transition Cost Balancing Account (TCBA) which tracks the amount of transition costs that must be recovered. These generation-related regulatory assets decreased by $1.4 billion for the nine months ended September 30, 2000, and decreased $955 million for the nine months ended September 30, 1999.

Certain transition costs can be recovered through a non-bypassable charge to distribution customers after the transition period. These costs include (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, (3) up to $95 million of transition costs to the extent that the recovery of such costs during the transition period was displaced by the recovery of electric industry restructuring implementation costs, and (4) transition costs financed by the rate reduction bonds. Transition costs financed by the issuance of rate reduction bonds will be recovered over the term of the bonds. In addition, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission the nuclear facility. During the rate freeze, the charge for these costs will not increase Utility customers' electric rates. Excluding these exceptions, the Utility will write off any transition costs not recovered during the transition period.

The Utility has been amortizing its transition costs, including most generation-related regulatory assets, over the transition period in conjunction with the available CTC revenues. During the transition period, a reduced rate of return on common equity of 6.77 percent applies to all generation assets, including those generation assets reclassified to regulatory assets. Beginning January 1, 1998, the Utility started collecting these eligible transition costs through the non-bypassable CTC, market valuation of generation assetsin excess of book value, and energy sales from the Utility's electric generation facilities prior to market valuation. Further, transition costs are reduced by the amount that contract prices to purchase power from QFs and other providers are lower than the PX price.

During the transition period, the CPUC reviews the Utility's compliance with accounting methods established in the CPUC's decisions governing transition cost recovery and the amount of transition costs requested for recovery. In February 2000, the CPUC approved substantially all non-nuclear transition costs that were amortized during the first six months of 1998. The CPUC currently is reviewing non-nuclear transition costs amortized from July 1, 1998, to June 30, 1999.

Under the electric industry restructuring law, when the Utility has recovered all of its transition costs the conditions for terminating the rate freeze and ending the transition period will have been satisfied. On August 9, 2000, a settlement agreement was filed by the Utility and others with the CPUC regarding the valuation and disposition of the Utility's hydroelectric assets, specifying that the value of those assets for purpose of transition cost calculation is $2.8 billion.

At August 31, 2000, consistent with transition cost recovery procedures adopted by the CPUC , the Utility credited its TCBA by $2.1 billion, the amount by which the value of the hydroelectric generating assets exceeded the aggregate book value of such assets. The Utility also established a separate regulatory asset in the same amount. The accounting entries were based on the value used in the proposed settlement discussed above. Based on the credit made to the TCBA, the Utility would have completed collection of all transition costs that must be collected during the transition period as of August 2000. If the hydroelectric assets were to be sold or valued at a higher amount, the Utility's transition costs would have been recovered as of an earlier date. Testimony taken to date in the CPUC proceeding in which valuation is to be established put the range of market values from $2.4 billion to in excess of $3 billion under operating and market conditions prior to June 2000. On October 16, 2000, the CPUC issued a ruling re-opening the proceeding to obtain more information from parties about market valuation in light of the different market conditions experienced during the summer of 2000. That new testimony is to be submitted in December 2000 with further testimony and evidentiary hearings scheduled for next year. The accounting entries discussed above are subject to later adjustment based on the final valuation of the hydroelectric assets adopted by the CPUC.

Under the electric industry restructuring law, after the Utility recovers its transition costs, the Utility's retail customers assume responsibility for wholesale energy costs. Actual changes in customer rates will not occur until the Utility files for new retail rates and the CPUC authorizes them.

During the transition period, the Utility is required to continue to use the transition period accounting mechanisms, discussed above. This requires that revenues from sales to the PX of Utility-owned generation and generation from QFs and other providers in excess of costs be credited to the TCBA. In addition, the TCBA balance includes a credit for the amount of PX revenues from the Utility's sale of generation from the Diablo Canyon nuclear power plant to the PX that exceed revenues from the fixed Incremental Cost Incentive Price (ICIP). (During 2000, the ICIP is 3.43 cents per kWh.) After taking into account the credit for the hydroelectric assets described above, at September 30, 2000, the Utility's TCBA had a credit balance of approximately $585 million. As mentioned above, the CPUC has issued a ruling indicating that it would reconsider certain of these accounting mechanisms noting that the CPUC has the authority to implement any necessary changes to the electric restructuring accounting provisions and cost recovery consistent with statutory requirements.

Generation Divestiture

In 1998, the Utility sold three fossil-fueled generation plants for $501 million. These three fossil-fueled plants had a combined book value at the time of the sale of $346 million and a combined capacity of 2,645 megawatts (MW).

On April 16, 1999, the Utility sold three other fossil-fueled generation plants for $801 million. At the time of sale, these three fossil-fueled plants had a combined book value of $256 million and a combined capacity of 3,065 MW.

On May 7, 1999, the Utility sold its complex of geothermal generation facilities for $213 million. At the time of sale, these facilities had a combined book value of $244 million and a combined capacity of 1,224 MW.

The gains from the sale of the fossil-fueled generation plants were used to offset other transition costs. Likewise, the loss from the sale of the complex of geothermal generation facilities is being recovered as a transition cost.

The Utility has retained a liability for required environmental remediation related to any pre-closing soil or groundwater contamination at the plants it has sold.

As discussed above, on August 9, 2000, the Utility and a number of interested parties filed an application with the CPUC requesting that the CPUC approve a settlement agreement reached by these parties in the Utility's proceeding to determine the market value of its hydroelectric generation assets. In this settlement agreement, the Utility indicated that it would transfer its hydroelectric generation assets, at a value of $2.8 billion, to an affiliate (referred to herein as PG&E CalHydro) that would not be subject to cost of service regulation by the CPUC.

PG&E CalHydro would hold and operate the assets, subject to a 40-year revenue sharing agreement (RSA) between PG&E CalHydro and the Utility. Under the RSA, PG&E CalHydro would be allowed to recover an authorized inflation-indexed operations and maintenance allowance, certain other expenses including an allowance for capital additions, and a return on capital investment. The return on equity (ROE) initially would be set at 12.50 percent and would be subject to an indexed adjustment trigger. Under the

RSA, 90 percent of the after-tax earnings received in excess of the agreed-upon costs (including the target ROE) would be returned to the Utility to be used as a credit against current costs charged to the Utility's distribution ratepayers. If market revenues were insufficient to recover the agreed-upon costs of operating the hydroelectric facilities (including the target ROE) over a multi-year period, 90 percent of the revenue shortfalls would be charged to the Utility to be recovered from distribution customers.

The RSA would become effective on the date that the CPUC order approving the settlement and the RSA becomes final and non-appealable, subject to termination by either the Utility or PG&E CalHydro in certain circumstances. The CPUC may accept the settlement or reject it, suggest changes to it, or adopt a different valuation approach. In addition, the transfer of the assets from the Utility to PG&E CalHydro will require the approval of the FERC.

At September 30, 2000, the book value of the Utility's net investment in hydroelectric generation assets was approximately $700 million. The above settlement, if approved, would result in a pre-tax charge of $2.1 billion. If the value of the hydroelectric generation assets is determined by any method other than a sale of the assets to an unrelated third party, a material charge to Utility earnings could result. The timing and nature of any such charge is dependent upon the valuation method and procedure adopted, and the method of implementation. The CPUC is not likely to consider the Utility's proposed settlement until next year, and it is uncertain at this time whether the settlement will be approved, modified or rejected, or withdrawn.

Post-Transition Period

The CPUC has established the Purchased Electric Commodity Account (PECA) for the Utility to track energy costs after the rate freeze and transition period end. In June 2000, the CPUC issued a decision in the second phase of the Utility's post-transition period electric ratemaking proceeding. Among other things, the CPUC determined that the PECA would reflect a pass-through of energy costs, possibly subject to after-the-fact reasonableness reviews.

After the rate freeze ends, Diablo Canyon will be operated as a competitive generator of electricity with revenues generated from prevailing market rates. During the rate freeze, Diablo Canyon's operating costs have been recovered through the incremental cost incentive price (ICIP) mechanism. The ICIP, which has been in place since January 1, 1997, is a performance-based mechanism that establishes a rate per kWh generated by the facility. The ICIP prices for 1999, 2000, and 2001 are 3.37 cents per kWh, 3.43 cents per kWh, and 3.49 cents per kWh, respectively.

As required by a prior CPUC decision on June 30, 2000, the Utility filed an application with the CPUC requesting approval of its proposal for sharing with ratepayers 50 percent of the post-rate freeze net benefits of operating Diablo Canyon. The net benefit sharing methodology proposed in the Utility's application would be effective at the end of the current electric rate freeze for the Utility's customers and would continue for as long as the Utility owned Diablo Canyon. Under the proposal, the Utility would share the net benefits of operating Diablo Canyon based on the audited profits from operations, determined consistent with the prior CPUC decisions. If Diablo Canyon experiences losses, such losses would be accrued and netted against profits in the calculation of the net benefits in subsequent periods (or against profits in prior periods if subsequent profits are insufficient to offset such losses). Any changes to the net sharing methodology must be approved by the CPUC.

Future Competition

Opening California's electric generation to competition has raised certain interest in introducing further competition in the electric industry. The CPUC has opened a rulemaking proceeding to examine the various issues associated with distributed generation. Distributed generation enables the siting of electric generation technologies in close proximity to electric demand, and raises issues about stranded costs (both within distribution and transmission systems), interconnection charges, and cost allocation. The CPUC staff has issued a report identifying options for possible CPUC consideration regarding the additional unbundling of the electric distribution function and evaluate the investor-owned utilities' role of default provider of electricity.

It is too early to predict what may come of these matters. PG&E Corporation is unable to predict when these issues will be addressed by the CPUC or whether the results will have any impact on the Utility.

PG&E NATIONAL ENERGY GROUP

PG&E National Energy Group has been formed to pursue opportunities created by the gradual restructuring of the energy industry across the nation. PG&E National Energy Group integrates our national power generation, gas transmission, and energy trading businesses. PG&E National Energy Group contemplates increasing PG&E Corporation's national market presence through a balanced program of acquisition and development of energy assets and businesses, while at the same time undertaking ongoing portfolio management of its assets and businesses. PG&E National Energy Group's ability to anticipate and capture profitable business opportunities created by restructuring will have a significant impact on PG&E Corporation's future operating results.

Independent Power Generation

Through PG&E Gen and its affiliates, we participate in the development, construction, operation, ownership, and management of non-utility electric generating facilities that compete in the United States power generation market. In September 1998, PG&E Corporation, through its indirect subsidiary USGen New England, Inc. (USGenNE), completed the acquisition of a portfolio of electric generation assets and power supply contracts from the New England Electric System (NEES). The purchased assets include hydroelectric, coal, oil, and natural gas generation facilities with a combined generating capacity of about 4,000 MW.

As part of the New England electric industry restructuring, the local utility companies were required to offer Standard Offer Service (SOS) to their retail customers. Retail customers may select alternative suppliers at any time. The SOS is intended to provide customers with a price benefit (the commodity electric price offered to the retail customer is expected to be less than the market price) for the first several years, followed by a price disincentive that is intended to stimulate the retail market.

Retail customers may continue to receive SOS through June 30, 2002, in New Hampshire (subject to early termination on December 31, 2000, at the discretion of the New Hampshire Public Service Commission), through December 31, 2004, in Massachusetts, and through December 31, 2009, in Rhode Island.

However, if customers choose an alternate supplier, they are precluded from going back to the SOS.

In connection with the purchase of the generation assets, USGenNE entered into wholesale agreements with certain of the retail companies of NEES to supply at specified prices the electric capacity and energy requirements necessary for their retail companies to meet their SOS obligations. These companies are responsible for passing on to us the revenues generated from the SOS. USGenNE currently is indirectly serving a large portion of the SOS electric capacity and energy requirements for these companies, except in New Hampshire. For the nine months ended September 30, 2000, the contract SOS price paid to generators was $.38 per kWh for generation. On March 1, 1999, Constellation Power Source, Inc. won the New Hampshire component of the SOS through a competitive bidding solicitation. On January 7, 2000, USGenNE paid approximately $15 million to a third party for this third party's assumption of 10 percent of the Massachusetts Electric Company/Nantucket Electric Company SOS and 40 percent of the Narragansett SOS.

Like other utilities, New England utilities previously entered into agreements with unregulated companies (e.g., qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA)) to provide energy and capacity at prices that are anticipated to be in excess of market prices. We assumed NEES' contractual rights and duties under several of these power purchase agreements. At September 30, 2000, these agreements provided for an aggregate 470 MW of capacity. However, NEES will make support payments to us toward the cost of these agreements. The support payments by NEES total $0.9 billion in the aggregate (undiscounted) and are due in monthly installments from September 1998 through January 2008. In certain circumstances, with our consent, NEES may make a full or partial lump sum accelerated payment.

Initially, approximately 90 percent of the acquired operating capacity, including capacity and energy generated by other companies and provided to us under power purchase agreements, is dedicated to servicing SOS customers. Currently, approximately 60 percent to 70 percent of the capacity is dedicated to serving SOS customers. To the extent that customers eligible to receive SOS choose alternate suppliers, or as these obligations are sold to other parties, this percentage will continue to decrease. As customers choose alternate suppliers, or the SOS obligations are sold, a greater proportion of the output of the acquired operating capacity will be subject to market prices.

Gas Transmission Operations

PG&E Corporation participates in the "midstream" portion of the gas business through PG&E GT NW. PG&E GT NW owns and operates gas transmission pipelines and associated facilities which extend over 612 miles from the Canada-U.S. border to the Oregon-California border. PG&E GT NW provides firm and interruptible transportation services to third party shippers on an open-access basis. Its customers are principally retail gas distribution utilities, electric utilities that use natural gas to generate electricity, natural gas marketing companies, natural gas producers, and industrial consumers.

On January 27, 2000, PG&E National Energy Group signed a definitive agreement providing for the sale of the stock of PG&E Gas Transmission, Texas Corporation and PG&E Gas Transmission Teco, Inc. (collectively, PG&E GT Texas). The consideration to be received by PG&E National Energy Group includes $279 million in cash, subject to adjustments for working capital, as well as the assumption by El Paso of liabilities associated with PG&E GT

Texas and debt having a book value of approximately $566 million.

In 1999, PG&E Corporation recognized a charge against earnings of $890 million after tax, or $2.42 per share, to reflect PG&E GT Texas' assets at their fair market value. The composition of the pre-tax charge is as follows: (1) an $819 million write-down of net property, plant, and equipment, (2) the elimination of the unamortized portion of goodwill, in the amount of $446 million, and (3) an accrual of $10 million representing selling costs.

Proceeds from the sale will be used to retire short-term debt associated with PG&E GT Texas' operations and for other corporate purposes. Closing of the sale, which is expected in the fourth quarter of 2000, is subject to approval under the Hart-Scott-Rodino Act.

Energy Trading

Through PG&E ET, we purchase bulk volumes of power and natural gas from PG&E Corporation affiliates and the wholesale market. We then schedule, transport, and resell these commodities, either directly to third parties or to other PG&E Corporation affiliates. PG&E ET also provides risk management services to PG&E Corporation's other businesses (except the Utility) and to wholesale customers. (See "Price Risk Management Activities" below; and Note 3 of the Notes to Condensed Consolidated Financial Statements.)

Energy Services

In December 1999, PG&E Corporation's Board of Directors approved a plan to dispose of PG&E ES, its wholly owned subsidiary, through a sale. The disposal has been accounted for as a discontinued operation and PG&E Corporation's investment in PG&E ES was written down to its then estimated net realizable value. In addition, PG&E Corporation provided a reserve for anticipated losses through the anticipated date of sale. The total provision for discontinued operations was $58 million, net of income taxes of $36 million. During the second quarter of 2000, PG&E National Energy Group finalized the transactions related to the disposal of PGE ES for $20 million, plus net working capital of approximately $65 million, for a total of $85 million. In addition, the sale of the Value-Added Services business and various other assets was completed on July 21, 2000, for a total consideration of $18 million. Both of these sales have working capital true-ups, which will not be finalized until 2001. For the three and nine months ended September 30, 2000, an additional estimated loss of $19 million (or $0.05 per share), net of income taxes of $13 million was recorded as actual and anticipated losses in connection with the disposition. The PG&E ES business segment generated net losses from operations of $34 million, net of income taxes of $26 million for the nine-month period ended September 30, 1999.

REGULATORY MATTERS

A significant portion of PG&E Corporation's operations are regulated by federal and state regulatory commissions. These commissions oversee service levels and, in certain cases, PG&E Corporation's revenues and pricing for its regulated services. The Utility is the only subsidiary with significant regulatory proceedings at this time. Any change in authorized electric revenues resulting from any of the electric proceedings discussed below would not impact the Utility's customer electric rates during the transition period because these rates are frozen. However, any change would affect the amount of revenues available for the recovery of transition costs. Any change in authorized gas revenues resulting from gas proceedings would result in a change in the Utility's customer gas rates. The Utility's pending proceedings to determine the method for sharing the net benefits of operating Diablo Canyon with ratepayers after the rate freeze and the value of its hydroelectric generation assets and how such valuation will affect the Utility's ability to recover its generation-related transaction costs are discussed above.

The 1999 General Rate Case (GRC)

The CPUC's final decision issued in February 2000 in the Utility's 1999 GRC application increased annual electric distribution revenues by $163 million and annual gas distribution revenues by $93 million, as compared to revenues authorized for 1998. Although the increase in electric and gas distribution revenues was retroactive to January 1, 1999, prior quarters were not restated. Instead, the entire increase was reflected in the fourth quarter of 1999. Had the Utility restated prior quarters, 1999 net earnings for the nine months ended September 30, 1999, would have been $115 million higher than reported.

In March 2000, two intervenors filed applications for rehearing of the GRC decision, alleging that the CPUC committed legal errors by approving funding in certain areas that were not adequately supported by record evidence. In April 2000, the Utility filed its response to these applications for rehearing, defending the GRC decision against the allegations of error. A CPUC decision on the applications for rehearing is expected by the end of 2000.

The 2002 General Rate Case (GRC)

Also in the 1999 GRC final decision, the CPUC ordered the Utility to file a 2002 GRC. In July 2000, the CPUC issued a decision requiring the Utility to file a Notice of Intent with the CPUC by May 1, 2001, a delay of nine months compared to the procedural timetable in effect for the 1999 GRC. The CPUC decision affirms that rates would still become effective on January 1, 2002, although the CPUC decision may not be rendered until late 2002.

The 2001 Attrition Rate Adjustment (ARA)

In July 2000, the Utility filed an ARA application with the CPUC to increase its 2001 electric distribution revenues by $189 million, effective January 1, 2001, to reflect inflation and the growth in capital investments necessary to serve customers. The Utility did not request an increase in gas distribution revenues. The Utility has requested expedited treatment of the application and has proposed a schedule to ensure that the 2001 ARA decision is issued before January 1, 2001. The assigned commissioner has issued a ruling that requires hearings on a number of issues and indicated that a final decision would be issued no later than January 2002. However, that ruling stated that the CPUC will consider an interim order that would allow the final decision to be effective on an earlier date. The Utility intends to file a request for an interim order granting the full attrition relief requested subject to refund or adjustment when the final decision is issued.

The Year 2000 Cost of Capital Proceeding

In June 2000, the CPUC issued a final decision in the Utility's 2000 cost of capital proceeding, adopting a return on common equity (ROE) of 11.22 percent on electric and gas distribution operations, retroactive to February 17, 2000, as compared to the Utility's former authorized ROE of 10.6 percent. The decision also affirmed the existing authorized Utility capital structure of 46.2 percent long-term debt, 5.8 percent preferred stock, and 48.0 percent common equity.

The decision results in an authorized 9.12 percent overall rate of return (ROR) on Utility electric and gas distribution rate base. The Utility's 2000 electric and gas revenues will increase by approximately $37 million and $12 million, respectively, for the period February 17, 2000, through December 31, 2000.

The Year 2001 Cost of Capital Proceeding

In May 2000, the Utility filed an application with the CPUC to establish its authorized ROR for electric and gas distribution operations for 2001. The application requests a ROE of 12.4 percent, and an overall ROR of 9.75 percent. The Utility's proposal for test year 2001 ROE for its electric distribution and gas distribution lines of business is 1.18 percent higher than the 2000 ROE of 11.22 percent. If granted, the requested ROR would increase electric distribution revenues by approximately $72 million and gas distribution revenues by approximately $23 million. The application also requests authority to implement an Annual Cost of Capital Adjustment Mechanism for 2002 through 2006 that would replace the annual cost of capital proceedings. The proposed adjustment mechanism would modify the Utility's cost of capital based on changes in an interest rate index. The Utility also proposes to maintain its currently authorized capital structure of 46.2 percent long-term debt, 5.8 percent preferred stock, and 48.0 percent common equity.

FERC Transmission Rate Cases

Since April 1998, electric transmission revenues have been authorized by the FERC, including various rates to recover transmission costs from the Utility's former bundled retail transmission customers. The FERC has not yet acted upon a settlement filed by the Utility that, if approved, would allow the Utility to recover $345 million in electric transmission rates for the 14-month period of April 1, 1998, through May 31, 1999. During this period, somewhat higher rates have been collected, subject to refund.

In the current year, the FERC has approved two settlements. In April 2000, the FERC approved a settlement that permits the Utility to recover $264 million in electric transmission rates retroactively for the 10-month period from May 31, 1999 to March 31, 2000. In September 2000, the FERC approved another settlement that permits the Utility to recover $340 million annually in electric transmission rates and made this retroactive to April 1, 2000.

In October 2000, the Utility filed a request to increase future revenues by $57 million annually to $397 million in electric transmission rates. The Utility does not expect a material impact on its financial position or results of operations resulting from these matters.

The CPUC's Gas Strategy Investigation, Phase 2

In January 1998, the CPUC opened a rulemaking proceeding to explore alternative market structures in the natural gas industry in California. In January 2000, the Utility and a broad-based coalition of shippers, consumer groups, marketers, and others filed a settlement with the CPUC which reaffirmed the basic structure of the Gas Accord and would continue the Gas Accord through its original term of December 31, 2002. In May 2000, the CPUC approved the uncontested settlement.

Performance-Based Ratemaking (PBR) Application

In June 2000, the CPUC granted the Utility's request to withdraw its PBR application filed in November 1998. The Utility had requested the withdrawal in accordance with the 1999 General Rate Case decision issued in February 2000, which required a 2002 GRC before a PBR revenue/rate indexing mechanism could be implemented. In closing the PBR proceeding, the CPUC ordered the Utility to file a new PBR application by September 2000, for financial rewards/penalties associated with utility performance in meeting prescribed standards on measures such as electric reliability and customer service.

In September 2000, the Utility filed an application with the CPUC to establish (1) performance standards and associated financial rewards and penalties for electric and gas distribution service (2) a revenue-sharing mechanism for new categories of non-tariffed products and services (NTP&S) offered by the Utility and (3) ratemaking for proceeds from sales or transfers of certain non-generation related land. The total maximum annual reward or penalty is $54 million per year, consisting of $52 million for electric distribution and $2 million for gas distribution. The revenue-sharing mechanism proposes to share net positive after-tax revenues from new categories of NTP&S equally between ratepayers and shareholders. Finally, the Utility requests that the CPUC establish basic rules about the allocation of gains and losses from the Utility's non-generation-related land sales.

RESULTS OF OPERATIONS

The table below presents for the three and nine months ended September 30, 2000 and 1999, certain items from our Condensed Consolidated Income Statement detailed by Utility and PG&E National Energy Group operations of PG&E Corporation. (In the Total column, the table shows the consolidated results of operations for these groups.) The information for PG&E Corporation (the Total column) includes the appropriate intercompany elimination. Following this table we discuss our results of operations.

	Utility	PG&E National Energy Group					
			PG&E GT				
(in millions)		PG&EGen	NW	Texas	PG&E ET	Eliminations & Other (1)	Total
For the three months ended September 30, 2000							
Operating revenues	$ 2,523	$ 290	$ 64	$ 258	$ 4,777	$ (408)	$ 7,504
Operating expenses	1,990	257	28	224	4,766	(390)	6,875

Operating income							629
Other income, net							45
Interest expense, net							191
Income taxes							239
Income from continuing operations							244
Net income							$ 225
EBITDA (2)	$ (446)	$ 58	$ 46	$ 28	$ 13	$ (19)	$ (320)
For the three months ended September 30, 1999							
Operating revenues	$ 2,587	$ 275	$ 56	$ 177	$ 3,490	$ (368)	$ 6,217
Operating expenses	2,101	255	26	174	3,521	(376)	5,701
Operating income							516
Other income, net							20
Interest expense, net							190
Income taxes							149
Income from continuing operations							197
Net income							$ 185
EBITDA (2)	$ 1,096	$ 43	$ 47	$ 17	$ (29)	$ 10	$ 1,184
For the nine months ended September 30, 2000							
Operating revenues	$ 7,037	$ 883	$ 177	$ 707	$ 10,493	$ (1,147)	$ 18,150
Operating expenses	5,382	763	77	657	10,468	(1,124)	16,223
Operating income							1,927
Other income, net							72
Interest expense, net							556
Income taxes							671
Income from continuing operations							772
Net income							$ 753
EBITDA (2)	$ 1,006	$ 187	$ 131	$ 37	$ 32	$ (24)	$ 1,369
For the nine months ended September 30, 1999							
Operating revenues	$ 6,905	$ 818	$ 166	$ 970	$8,145	$ (979)	$ 16,025
Operating expenses	5,545	742	76	1,001	8,181	(977)	14,568
Operating income							1,457
Other income, net							81
Interest expense, net							583
Income taxes							395
Income from continuing operations							560
Net income							$ 538
EBITDA (2)	$ 2,841	$ 157	$ 128	$ 22	$ (29)	$ 1	$ 3,120

(1) Net income on intercompany positions recognized by segments using mark-to-market accounting is eliminated. Intercompany transactions are also eliminated.

(2) EBITDA measures earnings (after preferred dividends) before interest expense (net of interest income), income taxes, depreciation, and amortization.

Overall Results

PG&E Corporation's net income for the third quarter of 2000 increased 21.6 percent to $225 million from $185 million in the prior year's third quarter. Of the $40 million increase, PG&E National Energy Group accounted for $8 million of the increase and the Utility's third quarter net income available for common stock accounted for $32 million of the increase.

Net income for the nine-month period ended September 30, 2000, increased 40.0 percent to $753 million from $538 million for the same period in 1999. Of the $215 million increase, PG&E National Energy Group accounted for $58 million of the increase and the Utility's net income available for common stock for the first nine months of 2000 accounted for $157 million of the increase.

The increase in performance is attributable to the following factors:

- In the first quarter of 2000, the Utility received the final order on its general rate case. Although the increase in revenue requirements was retroactive to January 1, 1999, the prior quarters were not restated and the entire increase was reflected in the fourth quarter of 1999. If the prior year's quarterly periods had been restated for the general rate case outcome, the rate order would have increased the 1999 third quarter Utility net earnings by approximately $38 million ($0.11 per share) and increased 1999 year-to-date earnings by approximately $115 million ($0.32 per share).

- In the second quarter of 2000, the Utility received a final decision from the CPUC increasing its authorized cost of capital from 10.6 percent to 11.22 percent, retroactive to February 2000, resulting in an approximate $7 million ($0.02 per share) and $18 million ($0.05 per share) increase in the 2000 third quarter and year-to-date earnings, respectively, as compared to similar periods in 1999.

- PG&E Energy Trading's (PG&E ET) third quarter 2000 net income before restructuring charges increased $22 million over 1999 third quarter results due to across the board improvements in gas and power trading, asset management, and structured transactions. This increase was offset by a $4 million after-tax ($.01 per share) charge associated with the restructuring of PG&E National Energy Group. PG&E ET's net income for the first nine months of 2000, net of restructuring charges of $13 million after-tax ($0.04 per share), increased $33 million compared to the same period of 1999.

- At the end of 1999, PG&E Corporation also announced its plans to dispose of PG&E GT Texas and these assets were written down to estimated fair value. PG&E GT Texas has operated at a breakeven basis in 2000 and reported losses of $7 million ($0.02 per share) and $33 million ($0.10 per share) for the three and nine months ended September 30, 1999, respectively.

- Effective the first quarter of 1999, PG&E Corporation changed its method of accounting for major maintenance and overhauls at PG&E National Energy Group. Beginning January 1, 1999, the cost of major maintenance and overhauls, principally at the PG&E Gen business segment, has been accounted for as incurred. The change resulted in PG&E Corporation recording income of $12 million after-tax ($0.03 per share), reflecting the cumulative effect of the change in accounting principle for the first nine months of 1999.

- At the end of 1999, PG&E Corporation announced its plans to dispose of PG&E Energy Services (PG&E ES) and these assets were written down to net realizable value. PG&E ES has operated at a breakeven basis in 2000 and reported losses of $12 million ($0.03 per share) and $34 million ($0.09 per share) for the three and nine months ended September 30, 1999, respectively. Additionally, during the third quarter of 2000, the Company recorded an after-tax charge of $19 million ($0.05 per share) to reflect the closing of transactions to dispose of the retail energy services business and related commodity portfolio.

Operating Revenues

Utility operating revenues decreased $64 million and increased $132 million in the third quarter and first nine months of 2000, respectively, compared to similar periods of the prior year. The decrease for the third quarter of 2000, as compared to the same period in 1999, is principally attributable to the effect of higher wholesale power market prices and resulting credits issued to direct access customers. These customers, principally large industrial companies, procure electricity from independent generators under long-term contracts and receive a credit on their utility bills at prevailing market prices.

The increase in operating revenues for the nine-month period ended September 30, 2000, as compared to the same period in 1999, relates to higher gas and electric sales to commercial and industrial customers due to their higher usage. Additionally, increases in the price of gas have increased revenues.

PG&E National Energy Group operating revenues increased $1,351 million and $1,993 million in the third quarter and first nine months of 2000, respectively, compared to similar periods of 1999. PG&E National Energy Group has focused its trading efforts on asset management, structured transactions, and higher-margin trades, resulting in increased trading volume principally in the Northeast. In addition, increases in the price of power and gas in the second and third quarters resulted in increased revenues.

Operating Expenses

Utility operating expenses decreased $111 million and $163 million in the three and nine month periods ended September 30, 2000, respectively, compared to similar periods of the prior year.

The tables below summarize the changes in the Utility's operating expenses:

	Three months ended September 30, 2000	Three months ended September 30, 1999	Increase (Decrease)	Increase (Decrease)
(in millions)				
Utility operating expenses:				
Cost of electric energy	$ 2,056	$ 746	$ 1,310	175.6%
Deferred electric procurement costs	(2,176)	-	(2,176)	-
Cost of gas	178	118	60	50.8%
Operating and maintenance, net	730	615	115	18.7%
Depreciation, amortization and decommissioning	1,202	622	580	93.2%

Total	$ 1,990	$ 2,101	$ (111)	(5.3)%

(in millions)	Nine months ended September 30, 2000	1999	Increase (Decrease)	Increase (Decrease)
Utility operating expenses:				
Cost of electric energy	$ 3,544	$ 1,681	$ 1,863	110.8%
Deferred electric procurement costs	(2,789)	-	(2,789)	-
Cost of gas	643	502	141	28.1%
Operating and maintenance, net	1,824	1,849	(25)	(1.4)%
Depreciation, amortization and decommissioning	2,160	1,513	647	42.8%
Total	$ 5,382	$ 5,545	$ (163)	(2.9)%

The overall decrease in operating expenses is attributable to the deferral of increased wholesale energy prices during the third quarter of 2000. To the extent that current operating costs, including the cost of electric energy, exceed frozen utility electric revenues, wholesale energy costs are deferred in accordance with California's transition plan.

The increase in depreciation expense of $580 million and $647 million, for the three and nine month period ended September 30, 2000, respectively, as compared to the same periods in the prior year, is attributable to the accelerated amortization arising from proceeds from sales to the PX being applied to offset transition costs in accordance with California's transition plan.

The increase in operating and maintenance expense reflects the impact in 2000 of an unscheduled 10-day outage at Diablo Canyon with no such outage in the same period of the prior year. The cost of electric energy and the cost of gas both increased for the quarter and year-to-date over comparable prior year periods because of increases in the volume of gas purchased and increases to the price of power and gas.

Operating expenses at PG&E National Energy Group increased $1,285 million and $1,818 million in the third quarter and first nine months of 2000, respectively, compared to the similar periods of the prior year. The increase results from the increased trading volumes discussed above, increases in the cost of power and gas, partially offset by reduced depreciation and amortization expense at PG&E GT Texas reflective of the disposal of the PG&E GT Texas assets.

EBITDA

PG&E Corporation's EBITDA has decreased $1,504 million and $1,751 million to ($320) million and $1,369 million for the third quarter and first nine months of 2000, respectively. The decreases are principally attributable to the impact of higher fuel prices at the Utility during the third quarter of 2000. The Utility defers the increased fuel costs in excess of the generation component in frozen rates through its regulatory balancing account mechanism in accordance with California's transition plan.

Income Taxes

The effective tax rate for the Corporation has increased to 46.5 percent in the first nine months of 2000 compared to 41.4 percent in the prior year's first nine months as a result of (1) electric industry restructuring which has resulted in the reversal of temporary tax differences at the Utility whose tax benefits were originally flowed through to customers independent of pre-tax income, and (2) higher state taxes.

Dividends

We base our common stock dividend on a number of financial considerations, including sustainability, financial flexibility, and competitiveness with investment opportunities of similar risk. Our current quarterly common stock dividend is $.30 per common share, which corresponds to an annualized dividend of $1.20 per common share. We continually review the level of our common stock dividend, taking into consideration the impact of the changing regulatory environment throughout the nation, the resolution of asset dispositions, the operating performance of our business units, and our capital and financial resources in general.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. The Utility has been in compliance with its CPUC-authorized capital structure. PG&E Corporation and the Utility believe that this requirement will not affect PG&E Corporation's ability to pay common stock dividends. However, depending on the timing and outcome of the valuation of the Utility's hydroelectric facilities discussed in "Generation Divestiture" above, certain valuation methods could necessitate a waiver of the CPUC's authorized capital structure in order to permit PG&E Corporation or the Utility to continue paying common stock dividends at the current level. In addition, a material write-off of net generation-related regulatory assets, including deferred electric procurement costs, or the Utility's inability to continue to defer future electric procurement costs, as discussed above, could necessitate a waiver of the CPUC's authorized capital structure in order to permit PG&E Corporation or the Utility to continue to pay common stock dividends at the current level.

LIQUIDITY AND FINANCIAL RESOURCES

Cash Flows from Operating Activities

Net cash provided by PG&E Corporation's operating activities totaled $1,210 million and $2,023 million during the nine months ended September 30, 2000 and 1999, respectively.

Utility:

Net cash provided by the Utility's operating activities totaled $1,297 million and $1,923 million during the nine months ended September 30, 2000 and 1999, respectively. High PX prices in the third quarter of 2000 have adversely impacted the amount of cash generated by the Utility from operations during these months. However, monthly payments to the ISO and PX are due 90 days after the end of the month of service increasing the Utility's accounts payable balance. The significant extent to which costs have exceeded revenues in recent months and are expected to continue to exceed current revenues, has caused the Utility to obtain additional sources of financing.

On October 19, 2000, the CPUC approved the Utility's request to increase its current authorized amount of short-term debt by $1.4 billion, raising the Utility's short-term debt authority to $3.1 billion. The additional $1.4 billion may only be used for the purpose of financing the purchase of wholesale power for delivery to the Utility's retail customers. The Utility has executed a credit agreement for an additional $1 billion in revolving credit facilities to provide commercial paper backup to support its higher purchased power costs and the associated increases in the TRA. The Utility is in the process of completing the sale of $670 million of 364-day Floating Rate Notes and $680 million of Senior Notes due on November 1, 2005 to meet financing needs under existing authorities. Additionally, the Utility has filed a request with the CPUC requesting authority to issue an additional $2 billion in long-term debt instruments. The Utility's liquidity will depend in significant part upon the extent to which regulatory bodies allow the Utility to recover in rates the deferred energy procurement costs discussed above.

PG&E National Energy Group:

We have entered into tolling agreements with several counterparties giving PG&E ET the rights to sell electricity generated by facilities owned and operated by another party. Under such arrangements, PG&E ET supplies the fuel to the power plant, and then sells the plant's output in the competitive market. At September 30, 2000, the annual estimated committed payments under such contracts range from approximately $1 million to $151 million, resulting in total committed payments over the next 22 years of approximately $2.5 billion.

Cash Flows from Financing Activities

We fund investing activities from cash provided by operations after capital requirements and, to the extent necessary, external financing. Our policy is to finance our investments with a capital structure that minimizes financing costs, maintains financial flexibility, and, with regard to the Utility, complies with regulatory guidelines. Based on cash provided from operations and our investing and disposition activities, we may repurchase equity and long-term debt in order to manage the overall size and balance of our capital structure.

PG&E Corporation maintains two $500 million revolving credit facilities, one of which expires in November 2000 and the other in 2002. These credit facilities are used to support the commercial paper program and other short-term liquidity needs. The facility expiring in 2000 may be extended annually for additional one-year periods upon agreement with the lending institutions. There was $587 million of commercial paper outstanding at September 30, 2000. PG&E Corporation introduced a $200 million Extendible Commercial Note (ECN) program during the third quarter of 1999. The ECN program supplements our short-term borrowing capability and is not supported by the credit facilities. There were $200 million of ECNs outstanding at September 30, 2000. Also, at September 30, 2000, PG&E Corporation has $819 million of short-term investments.

During the nine-month period ended September 30, 2000, we issued $52 million of common stock, primarily through the Dividend Reinvestment Plan and the stock option plan component of the Long-Term Incentive Program. During the nine-month period ended September 30, 2000, we paid dividends on our common stock of $325 million.

During the nine-month period ended September 30, 1999, we repurchased $534 million of our common stock. The 1999 repurchases were executed through accelerated share repurchase programs. Under the agreement, PG&E Corporation purchased 16.6 million shares of its common stock from a counterparty and entered into a forward contract with the counterparty. PG&E Corporation retained the risk of increases and the benefit of decreases in the price of the common shares purchased by the counterparty. PG&E Corporation had the option to settle its obligations under the forward contract with either cash or shares of its common stock. For the three- and nine-month periods ended September 30, 1999, this agreement caused the none and $0.01 dilution, respectively, reflected in PG&E Corporation's diluted earnings per share. This dilution was eliminated when the associated forward contract was settled.

In October 1999, the Board of Directors of PG&E Corporation authorized an additional $500 million for the purpose of repurchasing shares of the Corporation's common stock on the open market. This authorization supplements the approximately $40 million remaining from the amount previously authorized by the Board of Directors on December 17, 1997. The authorization for share repurchase extends through September 30, 2001. As of September 30, 2000, through our wholly owned subsidiary, we repurchased 7.2 million shares, at a cost of $159 million under this authorization.

Utility:

During the nine months ended September 30, 2000, the Utility paid dividends on its common stock of $375 million. In April 2000, the Utility repurchased from PG&E Corporation 11.9 million shares of its common stock at a cost of $275 million.

The Utility's long-term debt that either matured, was redeemed, or was repurchased during the nine months ended September 30, 2000, totaled $291 million. Of this amount, $213 million related to the Utility's rate reduction bonds maturing, and $78 million related to the maturities of various of the Utility's medium-term notes and other debt. As discussed above, The Utility is in the process of completing the sale of $1,350 million of Floating Rate and Senior Notes. On October 18, 2000, it filed a request with the CPUC requesting authority to issue an additional $2 billion in long-term debt. Although there can be no assurance, the Utility believes it will be able to obtain additional financing on acceptable terms and conditions.

The Utility maintains a $1 billion revolving credit facility, which expires in 2002. The Utility may extend the facility annually for additional one-year periods upon agreement with the banks. This facility is used to support the Utility's commercial paper program and other liquidity requirements. The total amount outstanding at September 30, 2000, backed by this facility, was $917 million in commercial paper. The next payments to the ISO and PX are due October 31, 2000. In the third quarter the Utility requested and received permission from the CPUC to increase its short-term borrowing authority by $1.4 billion to $3.1 billion. On October 18, 2000, it executed a credit agreement for an additional $1 billion in revolving credit facilities to provide commercial paper backup to support the higher purchased power costs experienced since June 2000. The Utility also introduced a $200 million ECN program which is not supported by the credit facilities. At September 30, 2000 there were no amounts outstanding under this program. At September 30, 2000, the Utility also had $242 million in short-term investments.

PG&E National Energy Group:

During the nine months ended September 30, 2000, PG&E National Energy Group retired $385 million of long-term debt.

PG&E Gen maintains two $550 million revolving credit facilities to support commercial paper programs, letters of credit and other short-term liquidity requirements. One facility expires in August 2001 and the other expires in 2003. The total amount of commercial paper outstanding at September 30, 2000 was $1 billion, with $500 million classified as noncurrent in the Condensed Consolidated Balance Sheet of PG&E Corporation.

In 1998, USGenNE, a subsidiary of PG&E Gen, established a $100 million revolving credit facility that expires in 2003. As of September 30, 2000, there was no outstanding balance on this facility.

PG&E GT NW maintains a $100 million revolving credit facility that expires in 2002, but has an annual renewal option allowing the facility to maintain a three-year duration. PG&E GT NW also maintains a $50 million 364-day credit facility that expires in 2001, but can be extended for successive 364-day periods. At September 30, 2000, PG&E GT NW had an outstanding commercial paper balance of $29 million, which is classified as noncurrent in the Condensed Consolidated Balance Sheet of PG&E Corporation.

PG&E GTT maintains four separate credit facilities that total $250 million and are guaranteed by PG&E Corporation. At September 30, 2000, PG&E GTT had $215 million of outstanding short-term bank borrowings related to these credit facilities. These lines are cancelable upon demand and bear interest at each respective bank's quoted money market rate. The borrowings are unsecured and unrestricted as to use.

Cash Flows from Investing Activities

Utility:

The primary uses of cash for investing activities are additions to property, plant, and equipment, unregulated investments in partnerships, and acquisitions.

The Utility's estimated capital spending for 2000 is approximately $1.3 billion, excluding capital expenditures for divested fossil and geothermal power plants. The Utility's capital expenditures for the nine months ended September 30, 2000, was $874 million.

PG&E National Energy Group:

Four natural gas-fueled combined-cycle power plants are currently under construction which when completed will be owned or leased by PG&E National Energy Group. These power plants, referred to as "merchant power plants," will sell power as a commodity in the competitive marketplace. The electricity generated by these plants will be sold on a wholesale basis to local utilities and power marketers, including PG&E ET, which, in turn, will sell it to industrial, commercial, and other electricity customers.

Millennium Power, a 360-MW power plant located in Massachusetts, is expected to begin commercial service in the last quarter of 2000. Lake Road Generating Plant (Lake Road), an approximately 790-MW power plant located in Connecticut, is expected to begin commercial service in 2001. La Paloma Generating Plant

(La Paloma), an approximately 1,050-MW power plant located in California, is expected to begin commercial service in 2002. On September 28, 2000, PG&E National Energy Group purchased the Attala Power Project. Attala is a 500 MW gas-fired combined cycle project, which is approximately 50 percent complete, located in Mississippi and is expected to begin commercial service by summer 2001. During the second quarter critical environmental permits were obtained for the Athens Generating Plant, an approximately 1,080-MW power plant located in New York, and the approximately 1,040-MW Harquahala generating project located in Arizona. Both plants are expected to begin commercial service in 2003.

Lake Road and La Paloma are being financed through synthetic leases with a third-party owner. PG&E National Energy Group will operate the plants under operating leases. The estimated cost to construct these plants is approximately $1.4 billion.

PG&E National Energy Group broke ground for the Madison Wind Power Project in New York in April 2000. This 11.5 MW project will be the largest wind generating facility in the Eastern United States and began commercial operation in October 2000.

In addition to the above projects under construction, PG&E National Energy Group has an additional 9,000 to 10,000 MW in development for commercial operation in the next five years. The expected commercial operation dates of the projects discussed above and the completion of future projects is subject to many factors, including but not limited to various regulatory and environmental approvals, adequate financing on satisfactory terms, competitive conditions including the expansion and retirement plans of others, market prices for electricity, future fuel prices, delays by third party contractors, and the availability of required equipment.

ENVIRONMENTAL MATTERS

We are subject to laws and regulations established to both maintain and improve the quality of the environment. Where our properties contain hazardous substances, these laws and regulations require us to remove those substances or remedy effects on the environment. (See Note 6 of Notes to Condensed Consolidated Financial Statement for further discussion of these matters.)

RISK MANAGEMENT ACTIVITIES

We have established a risk management policy that allows derivatives to be used for both hedging and non-hedging purposes (a derivative is a contract whose value is dependent on or derived from the value of some underlying asset). We use derivatives for hedging purposes primarily to offset underlying commodity price risks. We also participate in markets using derivatives to gather market intelligence, create liquidity, and maintain a market presence. Such derivatives include forward contracts, futures, swaps, and options. Net open positions often exist or are established due to PG&E Corporation's assessment of its response to changing market conditions. To the extent that PG&E Corporation has an open position, it is exposed to the risk that fluctuating market prices may adversely impact its financial results. Our risk management policy and the trading and risk management policies of our subsidiaries prohibit the use of derivatives whose payment formula includes a multiple of some underlying asset.

We prepare a daily assessment of our portfolio market risk exposure using value-at-risk and other methodologies that simulate future price movements in the energy markets to estimate the size and probability of future potential losses. The quantification of market risk using value-at-risk provides a consistent measure of risk across diverse energy markets and products. The use of this methodology requires a number of important assumptions, including the selection of a confidence level for losses, volatility of prices, market liquidity, and a holding period. PG&E Corporation's daily value-at-risk for commodity price sensitive derivative instruments as of September 30, 2000, was $2.8 million for trading activities and $12.2 million for non-trading activities.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, inadequate indication of the exposure of a portfolio to extreme price movements, and the inability to address the risk resulting from intra-day trading activities.

PG&E Corporation expects to adopt Statement of Financial Accounting Standards (SFAS) No. 133, as amended by SFAS No. 138, effective January 1, 2001. The Statement will require us to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings, or will be recognized in other comprehensive income until the hedged items are recognized in earnings. We currently are evaluating what the effect of SFAS No. 133 will be on the earnings and financial position of PG&E Corporation. However, we already use the mark-to-market method of accounting for our commodity non-hedging and risk management activities.

LEGAL MATTERS

In the normal course of business, both the Utility and PG&E Corporation are named as parties in a number of claims and lawsuits. (See Note 6 of Notes to Condensed Consolidated Financial Statements for further discussion of significant pending legal matters.)

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and Pacific Gas and Electric Company's primary market risk results from changes in energy prices and interest rates. We engage in price risk management activities for both non-hedging and hedging purposes. Additionally, we may engage in hedging activities using futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. (See Risk Management Activities, above.)

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For a description of material legal proceedings, see Note 6 of the PG&E Corporation and Pacific Gas and Electric Company Notes to Condensed

Consolidated Financial Statements under Part I, Item 1 above, as well as the Annual Report on Form 10-K filed by PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31. 1999, and the Quarterly Report on Form 10-Q filed by PG&E Corporation and Pacific Gas and Electric Company for the quarter ended March 31, 2000.

Item 5. Other Information

Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

Pacific Gas and Electric Company's earnings to fixed charges ratio for the nine months ended September 30, 2000, was 3.72. Pacific Gas and Electric Company's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2000, was 3.53. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into Registration Statement Nos. 33-62488, 33-64136, 33-50707, and 33-61959, relating to Pacific Gas and Electric Company's various classes of debt and first preferred stock outstanding.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits:

Exhibit 3.1	Bylaws of PG&E Corporation, dated as of August 22, 2000
Exhibit 3.2	Bylaws of Pacific Gas and Electric Company, dated as of August 22, 2000
Exhibit 11	Computation of Earnings Per Common Share
Exhibit 12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
Exhibit 12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
Exhibit 27.1	Financial Data Schedule for the quarter ended September 30, 2000, for PG&E Corporation
Exhibit 27.2	Financial Data Schedule for the quarter ended September 30, 2000, for Pacific Gas and Electric Company

(b) The following Current Reports on Form 8-K were filed during the third quarter of 2000 and through the date hereof (2):

1. August 9, 2000
   Item 5. Other Events
   Pacific Gas and Electric Company's
   Hydroelectric Generation Assets

2. September 14, 2000
   Item 5. Other Events

Pacific Gas and Electric Company's
Attrition Rate Adjustment Application

3. October 25, 2000
   Item 5. Other Events
   Third Quarter 2000 Consolidated Earnings,
   Pacific Gas and Electric Company's
   Wholesale Power Purchase Costs, and Other Matters

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(2) Unless otherwise noted, all Current Reports on Form 8-K were filed under both Commission File Number 1-12609 (PG&E Corporation) and Commission File Number 1-2348 (Pacific Gas and Electric Company).

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

CHRISTOPHER P. JOHNS

By CHRISTOPHER P. JOHNS
Vice President and Controller

PACIFIC GAS AND ELECTRIC COMPANY

KENT M. HARVEY

By KENT M. HARVEY
Senior Vice President-Chief Financial Officer, Controller and Treasurer

Dated: October 31, 2000

Exhibit Index

Exhibit No.	Description of Exhibit
3.1	Bylaws of PG&E Corporation, dated as of August 22, 2000
3.2	Bylaws of Pacific Gas and Electric Company, dated as of August 22, 2000
11	Computation of Earnings Per Common Share
12.1	Computation of Ratio of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
27.1	Financial Data Schedule for the quarter ended September 30, 2000 for PG&E Corporation
27.2	Financial Data Schedule for the quarter ended September 30, 2000 for Pacific Gas and Electric Company

SCHEDULE 14A INFORMATION

Proxy Statement Pursuant to Section 14(a) of
the Securities Exchange Act of 1934 (Amendment No.   )

Filed by the Registrant /x/
Filed by a party other than the Registrant / /

Check the appropriate box:
/ / Preliminary Proxy Statement
/ / Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))
/x/ Definitive Proxy Statement
/ / Definitive Additional Materials
/ / Soliciting Material Pursuant to Section 240.14a-11(c) or Section 240.14a-12

PG & E CORPORATION

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

/x/ No fee required

/ / Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11

(1) Title of each class of securities to which transaction applies:

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(2) Aggregate number of securities to which transaction applies:

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(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

---

(4) Proposed maximum aggregate value of transaction:

---

(5) Total fee paid:

/ / Fee paid previously with preliminary materials.

/ / Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

---

(2) Form, Schedule or Registration Statement No.:

---

(3) Filing Party:

---

(4) Date Filed:

[PG&E LOGO] PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY

Joint Notice of 2000 Annual Meetings - Joint Proxy Statement

March 13, 2000

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

You are cordially invited to attend the fourth annual meeting of PG&E Corporation and the 94th annual meeting of Pacific Gas and Electric Company. The meetings will be held concurrently on Wednesday, April 19, 2000, at 10:00 a.m., at the Four Seasons Hotel - Boston, 200 Boylston Street, Boston, Massachusetts.

PG&E Corporation is a national energy-based holding company, with businesses that include a diverse group of U.S.-based power generating, gas pipeline, and energy commodity trading and services businesses. PG&E Corporation also is the parent company of Pacific Gas and Electric Company, the regulated utility that delivers gas and electricity to one in every 20 Americans.

The accompanying Joint Proxy Statement contains information about matters to be considered at both the PG&E Corporation and Pacific Gas and Electric Company annual meetings. At the annual meetings, PG&E Corporation and Pacific Gas and Electric Company shareholders will be asked to vote on the election of directors and ratification of the selection of independent public accountants for 2000 for their respective companies. The Boards of Directors and management of PG&E Corporation and Pacific Gas and Electric Company recommend that you vote "FOR" the nominees for directors and the ratification of the appointment of Deloitte & Touche as the independent public accountants for 2000, as set forth in the Joint Proxy Statement.

In addition to the matters described above, PG&E Corporation shareholders will be asked to vote on two management proposals to amend PG&E Corporation's Articles of Incorporation. The first proposal implements the elimination of a "supermajority vote" provision in the corporation's Articles of Incorporation, consistent with a vote of the shareholders at the 1999 Annual Meeting, and makes related changes. The second management proposal, which amends the corporation's Articles of Incorporation, reduces the size of the PG&E Corporation Board of Directors to a range of seven to 13 directors, from the current authorized range of nine to 17. For the reasons stated in the Joint Proxy Statement, the PG&E Corporation Board of Directors and management recommend that PG&E Corporation shareholders vote "FOR" these proposals.

PG&E Corporation shareholders also will be asked to vote on the proposals submitted by individual PG&E Corporation shareholders described in the Joint Proxy Statement, if such proposals are properly presented at the annual meeting. For the reasons stated in the Joint Proxy Statement, the PG&E Corporation Board of Directors and management recommend that PG&E Corporation shareholders vote "AGAINST" these proposals.

Your vote on the business at the annual meetings is important. If you hold shares in both PG&E Corporation and Pacific Gas and Electric Company, you will be provided with a separate proxy form for each company. Whether or not you plan to attend, please mark, sign, date, and mail your proxy form as soon as possible in the accompanying envelope so that your shares can be represented at the annual meetings. As an alternative to mailing your proxy, you may have the option of executing and submitting your proxy and voting instructions over the Internet or by telephone. Please refer to "Voting on the Internet or by Telephone" on page 39 of the Joint Proxy Statement for details.

During the annual meetings, PG&E Corporation and Pacific Gas and Electric Company management also will report on operations and other matters affecting PG&E Corporation and Pacific Gas and Electric Company, act on such other matters as may properly be presented at the meetings, and respond to shareholders' questions.

Sincerely,

[/S/ ROBERT D. GLYNN, JR.]

Robert D. Glynn, Jr.
Chairman of the Board, Chief Executive Officer,
and President of PG&E Corporation
Chairman of the Board of
Pacific Gas and Electric Company

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Joint Notice of Annual Meetings of Shareholders
of PG&E Corporation and Pacific Gas and Electric Company

March 13, 2000

TO THE SHAREHOLDERS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY:

The annual meetings of shareholders of PG&E Corporation and Pacific Gas and Electric Company will be held concurrently on Wednesday, April 19, 2000, at 10:00 a.m., at the Four Seasons Hotel - Boston, 200 Boylston Street, Boston, Massachusetts, for the purpose of considering the following matters:

(1) For PG&E Corporation and Pacific Gas and Electric Company shareholders, to elect the following 11 and 12 directors, respectively, to each Board for the ensuing year:

Richard A. Clarke	William S. Davila	Carl E. Reichardt
Harry M. Conger	Robert D. Glynn, Jr.	John C. Sawhill
David A. Coulter	David M. Lawrence, MD	Gordon R. Smith*
C. Lee Cox	Mary S. Metz	Barry Lawson Williams

* Gordon R. Smith is a nominee for director of the Pacific Gas and Electric Company Board only.

(2) For PG&E Corporation and Pacific Gas and Electric Company shareholders, to ratify each Board of Directors' appointment of Deloitte & Touche as independent public accountants for 2000 for PG&E Corporation and Pacific Gas and Electric Company,

(3) For PG&E Corporation shareholders only, to act upon two management proposals described on pages 14-16 of the Joint Proxy Statement,

(4) For PG&E Corporation shareholders only, to act upon six proposals submitted by PG&E Corporation shareholders and described on pages 17-24 of the Joint Proxy Statement, if such proposals are properly presented at the meeting, and

(5) For PG&E Corporation and Pacific Gas and Electric Company shareholders, to transact such other business as may properly come before the meetings and any adjournments or postponements thereof.

Shareholders of record of PG&E Corporation and Pacific Gas and Electric Company at the close of business on February 22, 2000, and valid proxyholders may attend and vote at the respective annual meetings. If your shares are registered in the name of a brokerage firm, bank, or trustee and you plan to attend the meeting, please obtain from the firm, bank, or trustee a letter or other evidence of your beneficial ownership of those shares to facilitate your admittance to the meeting.

If you are a participant in the PG&E Corporation Dividend Reinvestment Plan, please note that the PG&E Corporation proxy covers all shares of common stock in your account with PG&E Corporation, including any shares which may be held in that plan. If you hold shares in both PG&E Corporation and Pacific Gas and Electric Company, you will be provided with a separate proxy form for each company. Please mark, sign, date, and mail the proxy form promptly in the accompanying envelope.

If your shares are registered directly with PG&E Corporation and/or Pacific Gas and Electric Company (including shares held by participants in the PG&E Corporation Dividend Reinvestment Plan) or if you are a participant who holds PG&E Corporation stock in any of the defined contribution retirement plans maintained by PG&E Corporation or any of its subsidiaries, you have the option of executing and submitting your proxy and voting instructions over the Internet at http://www.eproxy.com/pcg/ or by telephone by calling the toll-free number 1-800-435-6710 from anywhere in the United States or Canada. If your PG&E Corporation and/or Pacific Gas and Electric Company shares are held in an account at a brokerage firm or bank, you also may have the option of submitting your voting instructions over the Internet at http://www.proxyvote.com or by telephone by calling the toll-free telephone number shown on the voting instruction form; these voting options are provided by ADP Investor Communication Services on behalf of participating brokerage firms and banks. Please refer to "Voting on the Internet or by Telephone" on page 39 of the Joint Proxy Statement for details.

By Order of the Boards of Directors,

[/S/ LESLIE H. EVERETT]

Leslie H. Everett
Vice President and Corporate
Secretary,
PG&E Corporation and
Pacific Gas and Electric Company

PG&E Corporation
Pacific Gas and Electric Company

JOINT PROXY STATEMENT

INTRODUCTION

This Joint Proxy Statement is provided to the shareholders of PG&E Corporation and Pacific Gas and Electric Company in connection with their respective annual meetings of shareholders and any adjournments or postponements thereof. The annual meetings are scheduled to be held concurrently on Wednesday, April 19, 2000, at 10:00 a.m., at the Four Seasons Hotel - Boston, 200 Boylston Street, Boston, Massachusetts.

As a result of the formation of PG&E Corporation in 1997, the outstanding shares of Pacific Gas and Electric Company common stock were converted, on a one-for-one basis, into shares of PG&E Corporation common stock. PG&E Corporation and a subsidiary hold 100 percent of the issued and outstanding shares of Pacific Gas and Electric Company common stock. Together they own approximately 95 percent of the total outstanding voting stock of Pacific Gas and Electric Company. The outstanding shares of Pacific Gas and Electric Company's first preferred stock are unchanged by the merger and continue to be outstanding shares of that company. Holders of Pacific Gas and Electric Company's first preferred stock hold approximately 5 percent of the Company's total outstanding voting stock.

GENERAL INFORMATION

The Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company are soliciting proxies hereunder for use at their respective annual meetings to be held on April 19, 2000, and at any adjournments or postponements thereof, and a respective form of proxy is provided with this Joint Proxy Statement. This Joint Proxy Statement and the accompanying proxy form were first mailed on or about March 13, 2000, to PG&E Corporation and Pacific Gas and Electric Company shareholders entitled to vote at the annual meetings.

To the knowledge of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company, the only items of business to be considered at the meetings are listed in the preceding PG&E Corporation and Pacific Gas and Electric Company Joint Notice of Annual Meetings of Shareholders and are explained in more detail on the following pages. By executing and submitting your proxy and voting instructions, you authorize the proxyholders named in the proxy to vote your shares as you indicate on these items of business and to vote your shares in accordance with management's best judgment in response to other proposals properly presented at the meeting.

As an alternative to executing and submitting your proxy and voting instructions by mail, you may have the option of executing and submitting your proxy and voting instructions over the Internet or by telephone. Please refer to "Voting on the Internet or by Telephone" on page 39 for further details. The use of Internet or telephone voting procedures will not affect your right to vote in person should you decide to attend the annual meeting.

You may revoke your proxy at any time before it is exercised at the annual meeting. You may do this by advising the Vice President and Corporate Secretary of PG&E Corporation or Pacific Gas and Electric Company (as the case may be) in writing of your desire to revoke your proxy, or by submitting a duly executed proxy bearing a later date. You also may revoke your proxy by attending the annual meeting and indicating that you wish to vote in person.

The Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company have established February 22, 2000, as the record date for the determination of shareholders of PG&E Corporation and Pacific Gas and Electric Company entitled to receive notice of and to vote at their respective annual meetings. As of February 22, 2000, there were 361,010,299 shares of PG&E Corporation common stock, without par value, outstanding and entitled to vote at the PG&E Corporation annual meeting; each such share is entitled to one vote. As of February 22, 2000, there were 17,258,280 shares of Pacific Gas and Electric Company first preferred stock, $25 par value, and 326,926,667 shares of Pacific Gas and Electric Company common stock, $5 par value, outstanding and entitled to vote at the Pacific Gas and Electric Company annual meeting; each such share is entitled to one vote.

Shares represented by properly executed proxies received by PG&E Corporation or Pacific Gas and Electric Company prior to or at the annual meetings will be voted at the respective annual meetings in accordance with the instructions specified in each proxy, and will be counted for purposes of establishing a quorum, regardless of how or whether such shares are voted on any specific proposal. If no instructions are specified in the PG&E Corporation proxy, the subject shares will be voted (1) FOR the election of the nominees of the PG&E Corporation Board of Directors, unless authority to vote is withheld as provided in the proxy, (2) FOR ratification of the appointment of Deloitte & Touche as PG&E Corporation's independent public accountants for 2000, (3) FOR the management proposal to amend PG&E Corporation's Articles of Incorporation to implement the elimination of a "supermajority vote" provision, (4) FOR the management proposal to amend PG&E Corporation's Articles of Incorporation to reduce the size of the Board of Directors to a range of between seven and 13, and (5) AGAINST each of the shareholder proposals that are properly presented at the meeting. If no instructions are specified in the Pacific Gas and Electric Company proxy, the subject shares will be voted (1) FOR the election of the nominees of the Pacific Gas and Electric Company Board of Directors, unless authority to vote is withheld as provided in the proxy, and (2) FOR ratification of the appointment of Deloitte & Touche as Pacific Gas and Electric Company's independent public accountants for 2000.

The management proposals to amend PG&E Corporation's Articles of Incorporation must be approved by a majority of the outstanding shares of voting stock of PG&E Corporation. Except with respect to the election of directors, each other proposal which may be presented at the meetings must receive the affirmative vote of a majority of the shares represented and voting on the proposal. In addition, the affirmative votes must constitute at least a majority of the required quorum (i.e., more than 25 percent of the outstanding shares of voting stock of PG&E Corporation or Pacific Gas and Electric Company, as the case may be). The required quorum is a majority of the outstanding shares of voting stock of PG&E Corporation or Pacific Gas and Electric Company (as the case may be). PG&E Corporation and Pacific Gas and Electric Company intend to count abstentions both for purposes of determining the presence or absence of a quorum and in the total number of shares represented and voting with respect to a proposal. Accordingly, abstentions will have the same effect as a vote against a proposal. Broker non-votes, if any, with respect to a proposal will be counted for purposes of determining the presence or absence of a quorum, but will not be counted as shares represented and voting with respect to that proposal. Broker non-votes occur when brokers or nominees have voted on some of the matters to be acted on at a meeting, but fail to vote on certain other matters because, under the rules of the New York Stock Exchange, they are not permitted to vote on such other matters in the absence of instructions from the beneficial owners of shares.

Item No. 1:
Election of Directors of PG&E Corporation and
Pacific Gas and Electric Company

Eleven and 12 directors will be elected to serve on the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company, respectively, to hold office until the next annual meetings or until their successors shall be elected and qualified. The 11 nominees for director of PG&E Corporation and the 12 nominees for director of Pacific Gas and Electric Company whom the respective Boards propose for election are the same, except for Gordon R. Smith, who is a nominee for the Pacific Gas and Electric Company Board only. The composition of these slates of nominees is consistent with the policy of PG&E Corporation and Pacific Gas and Electric Company that at least 75 percent of their Boards shall be composed of directors who are neither current nor former officers or employees of PG&E Corporation, Pacific Gas and Electric Company, or any of their respective subsidiaries.

Information is provided on the following pages about the nominees for directors, including their principal occupations for the past five years, certain other directorships, age, and length of service as a director of PG&E Corporation and Pacific Gas and Electric Company. Membership on Board committees, attendance at Board and committee meetings, and ownership of stock in PG&E Corporation and Pacific Gas and Electric Company are indicated in separate sections following the individual resumes of the nominees.

Directors of PG&E Corporation and Pacific Gas and Electric Company are elected from those nominated based on a plurality of votes cast. The nominees receiving the highest number of affirmative votes (up to the number of directors to be elected) are elected. Votes against a nominee or votes withheld have no legal effect. Unless authority to vote is withheld or another contrary instruction is indicated, properly executed proxies received by PG&E Corporation or Pacific Gas and Electric Company prior to or at the annual meetings will be voted FOR the election of the nominees listed on the following pages. All of the nominees named below have agreed to serve if elected. Should any of the nominees become unavailable at the time of the meeting to accept nomination or election as a director, the respective proxyholders named in the enclosed PG&E Corporation or Pacific Gas and Electric Company proxy will vote for substitute nominees at their discretion.

THE BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY RECOMMEND THE ELECTION OF THEIR RESPECTIVE NOMINEES FOR DIRECTOR PRESENTED IN THIS JOINT PROXY STATEMENT.

Nominees for Directors of PG&E Corporation and
Pacific Gas and Electric Company
BIOGRAPHICAL INFORMATION

[PHOTO]

RICHARD A. CLARKE

Mr. Clarke is former Chairman of the Board of Pacific Gas and Electric Company. He was Chairman of the Board of Pacific Gas and Electric Company from May 1986 until his retirement in May 1995, and also was Chief Executive Officer of Pacific Gas and Electric Company from May 1986 to June 1994. Mr. Clarke, 69, has been a director of Pacific Gas and Electric Company since 1985 and a director of PG&E Corporation since December 1996. He also is a director of CNF Transportation Inc. and Potlatch Corporation.

[PHOTO]

HARRY M. CONGER

Mr. Conger is Chairman and Chief Executive Officer, Emeritus of Homestake Mining Company. He was Chairman of the Board of Homestake Mining Company from 1982 until July 1998 and Chief Executive Officer from December 1978 until his retirement in May 1996. Mr. Conger, 69, has been a director of Pacific Gas and Electric Company since 1982 and a director of PG&E Corporation since December 1996. He also is a director of Apex Silver Mines Limited and ASA Limited.

[PHOTO]

DAVID A. COULTER

Mr. Coulter is a Partner in the Beacon Group, L.P. He is former Chairman and Chief Executive Officer of BankAmerica Corporation and Bank of America NT&SA. He joined Bank of America in 1976 and held a variety of senior management positions with BankAmerica Corporation and Bank of America NT&SA until October 1998. Mr. Coulter, 52, has been a director of Pacific Gas and Electric Company since May 1996 and a director of PG&E Corporation since December 1996.

[PHOTO]

C. LEE COX

Mr. Cox is retired Vice Chairman of AirTouch Communications, Inc. and retired President and Chief Executive Officer of AirTouch Cellular (cellular telephone and paging services). He was an executive officer of AirTouch Communications, Inc. and its predecessor, PacTel Corporation, from 1987 until his retirement in April 1997. Mr. Cox, 58, has been a director of Pacific Gas and Electric Company since February 1996 and a director of PG&E Corporation since December 1996.

[PHOTO]

WILLIAM S. DAVILA

Mr. Davila is President Emeritus of The Vons Companies, Inc. (retail grocery). He was President of The Vons Companies, Inc. from 1986 until his retirement in May 1992. Mr. Davila, 68, has been a director of Pacific Gas and Electric Company since 1992 and a director of PG&E Corporation since December 1996. He also is a director of Home Depot, Inc., Hormel Foods Corporation, and Wells Fargo & Company.

[PHOTO]

ROBERT D. GLYNN, JR.

Mr. Glynn is Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation and Chairman of the Board of Pacific Gas and Electric Company. He has been an officer of PG&E Corporation since December 1996 and an officer of Pacific Gas and Electric Company since January 1988. Mr. Glynn, 57, has been a director of Pacific Gas and Electric Company since 1995 and a director of PG&E Corporation since December 1996.

[PHOTO]

DAVID M. LAWRENCE, MD

Dr. Lawrence is Chairman and Chief Executive Officer of Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals, and has been an executive officer of those companies for more than the past five years. Dr. Lawrence, 59, has been a director of Pacific Gas and Electric Company since 1995 and a director of PG&E Corporation since December 1996. He also is a director of Agilent Technologies Inc.

[PHOTO]

MARY S. METZ

Dr. Metz is President of S. H. Cowell Foundation, and has held that position since January 1999. Prior to that date, she was Dean of University Extension, University of California, Berkeley from July 1991 to June 1998. Dr. Metz, 62, has been a director of Pacific Gas and Electric Company since 1986 and a director of PG&E Corporation since December 1996. She also is a director of Longs Drug Stores Corporation, SBC Communications, and UnionBanCal Corporation.

[PHOTO]

CARL E. REICHARDT

Mr. Reichardt is retired Chairman of the Board and Chief Executive Officer of Wells Fargo & Company (bank holding company) and Wells Fargo Bank, N.A. He was an executive officer of Wells Fargo Bank, N.A. from 1978 until his retirement in December 1994. Mr. Reichardt, 68, has been a director of Pacific Gas and Electric Company since 1985 and a director of PG&E Corporation since December 1996. He also is a director of Columbia/HCA Healthcare Corporation, ConAgra, Inc., Ford Motor Company, McKesson HBOC, Inc., and Newhall
Management Corporation.

[PHOTO]

JOHN C. SAWHILL

Dr. Sawhill is President and Chief Executive Officer of The Nature Conservancy (international environmental organization) and has held that position since April 1990. Dr. Sawhill, 63, has been a director of Pacific Gas and Electric Company since 1990 and a director of PG&E Corporation since December 1996. He also is a director of NACCO Industries, Inc., Newfield Exploration Company, Procter and Gamble, The Vanguard Group, Inc., and each of the Vanguard Funds, registered investment companies.

Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company CONTINUED

[PHOTO]

GORDON R. SMITH*

Mr. Smith is President and Chief Executive Officer of Pacific Gas and Electric Company, and has been an officer of Pacific Gas and Electric Company since June 1980. Mr. Smith, 52, has been a director of Pacific Gas and Electric Company since 1997.

[PHOTO]

BARRY LAWSON WILLIAMS

Mr. Williams is President of Williams Pacific Ventures, Inc. (business consulting and mediation), and has held that position since May 1987. Mr. Williams, 55, has been a director of Pacific Gas and Electric Company since 1990 and a director of PG&E Corporation since December 1996. He also is a director of CH2M Hill Companies, Ltd., CompUSA Inc., Newhall Management Corporation, R.H. Donnelley Inc., and Simpson Manufacturing Company Inc.

* Gordon R. Smith is a nominee for director of Pacific Gas and Electric Company only.

Information Regarding the
Boards of Directors of PG&E Corporation and
Pacific Gas and Electric Company

BOARD COMMITTEES

The committees of the PG&E Corporation Board of Directors are the Executive Committee, Audit Committee, Finance Committee, Nominating and Compensation Committee, and Public Policy Committee. The Pacific Gas and Electric Company Board of Directors has an Executive Committee. The current membership and duties of these committees are as follows:

EXECUTIVE COMMITTEES	AUDIT COMMITTEE	FINANCE COMMITTEE	NOMINATING AND COMPENSATION COMMITTEE	PUBLIC POLICY COMMITTEE
R. D. Glynn, Jr.*	H. M. Conger*	B. L. Williams*	C. E. Reichardt*	M. S. Metz*
H. M. Conger	C. L. Cox	R. A. Clarke	D. A. Coulter	R. A. Clarke
M. S. Metz	W. S. Davila	D. A. Coulter	C. L. Cox	W. S. Davila
C. E. Reichardt	M. S. Metz	C. E. Reichardt	D. M. Lawrence, MD	J. C. Sawhill
G. R. Smith(1)	B. L. Williams	J. C. Sawhill	J. C. Sawhill	
B. L. Williams				

* Chair

(1) Member of the Pacific Gas and Electric Company Executive Committee only.

EXECUTIVE COMMITTEES

Each Executive Committee, subject to the provisions of law and certain limits imposed by the PG&E Corporation or the Pacific Gas and Electric Company Board (as the case may be), may exercise any of the powers and perform any of the duties of the PG&E Corporation Board or the Pacific Gas and Electric Company Board, respectively. The Executive Committees meet as needed. One PG&E Corporation Executive Committee meeting was held in 1999 and no Pacific Gas and Electric Company Executive Committee meetings were held in 1999.

AUDIT COMMITTEE

The Audit Committee of PG&E Corporation (five meetings were held in 1999) advises and assists the Board in fulfilling its responsibilities in connection with financial and accounting practices, internal controls, external and internal auditing programs, business ethics, and compliance with laws, regulations, and policies that may have a material impact on the consolidated financial statements of PG&E Corporation and its subsidiaries. The Audit Committee satisfies itself as to the independence and competence of PG&E Corporation's and Pacific Gas and Electric Company's independent public accountants, and reviews and discusses with the independent accountants and with PG&E Corporation's or Pacific Gas and Electric Company's officers and internal auditors the scope and results of the independent accountants' audit work, consolidated quarterly and annual financial statements, internal audit and control systems, and compliance with laws, regulations, policies, and programs. The Audit Committee also recommends to the Board of Directors the firm of independent public accountants to be selected to audit PG&E Corporation's and Pacific Gas and Electric Company's accounts, and makes further inquiries as it deems necessary or desirable to inform itself as to the conduct of PG&E Corporation's or its subsidiaries' affairs.

The Audit Committee is composed entirely of directors who are (a) neither current nor former officers or employees of PG&E Corporation or any of its subsidiaries, (b) not consultants to PG&E Corporation or any of its subsidiaries, and (c) neither current nor former officers or employees of any other corporation on whose board of directors any PG&E Corporation officer serves as a member. One member of the Committee is appointed by the Board of Directors as the Committee's Chair.

FINANCE COMMITTEE

The Finance Committee of PG&E Corporation (eight meetings were held in 1999) advises and assists the Board with respect to the financial and capital investment policies and objectives of PG&E Corporation and its subsidiary companies, including specific actions required to achieve those objectives. The Finance Committee reviews long-term financial and investment plans and strategies, annual financial plans, dividend policy, short-term and long-term financing plans, proposed capital investments, proposed divestments, major commercial banking, investment banking, financial consulting, and other financial relations of PG&E Corporation or its subsidiaries, and price risk management activities.

One member of the Committee, who is neither a current nor former employee of, nor current consultant to, PG&E Corporation or any of its subsidiaries, is appointed by the Board of Directors as the Committee's Chair.

NOMINATING AND COMPENSATION COMMITTEE

The Nominating and Compensation Committee of PG&E Corporation (five meetings were held in 1999) advises and assists the Boards of PG&E Corporation and Pacific Gas and Electric Company with respect to the selection and compensation of directors. It also advises and assists PG&E Corporation and its subsidiaries on employment, compensation, benefits policies and practices, and the development, selection, and compensation of policy-making officers. The Nominating and Compensation Committee reviews and acts upon the compensation of officers of PG&E Corporation and its subsidiaries, except that the compensation of the Chief Executive Officers of PG&E Corporation and Pacific Gas and Electric Company is established by the full PG&E Corporation or Pacific Gas and Electric Company Board (as the case may be) upon recommendation of the Committee, and the Committee has delegated to the PG&E Corporation Chief Executive Officer the authority to approve compensation for certain officers of PG&E Corporation and its subsidiaries. The Committee also reviews long-range planning for executive development and succession, and the composition and performance of the Boards of PG&E Corporation and Pacific Gas and Electric Company.

The Nominating and Compensation Committee is composed entirely of directors who are (a) neither current nor former officers or employees of PG&E Corporation or any of its subsidiaries, (b) not consultants to PG&E Corporation or any of its subsidiaries, and (c) neither current nor former officers or employees of any other corporation on whose board of directors any PG&E Corporation officer serves as a member. One member of the Committee is appointed by the Board of Directors as the Committee's Chair.

The Nominating and Compensation Committee will consider nominees recommended by shareholders for election to the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company. The names of such nominees, accompanied by relevant biographical information, should be submitted in writing to the Vice President and Corporate Secretary of PG&E Corporation or Pacific Gas and Electric Company (as the case may be). The Nominating and Compensation Committee seeks qualified, dedicated, and highly regarded individuals who have experience relevant to PG&E Corporation's or Pacific Gas and Electric Company's business operations, who understand the complexities of PG&E Corporation's or Pacific Gas and Electric Company's business environment, and who will represent the best interests of all the shareholders of PG&E Corporation or Pacific Gas and Electric Company. In accordance with PG&E Corporation's and Pacific Gas and Electric Company's commitment to equal opportunity, the Committee continues to seek qualified women and minority candidates for the Boards.

PUBLIC POLICY COMMITTEE

The Public Policy Committee of PG&E Corporation (three meetings were held in 1999) advises and assists the Board of Directors with respect to public policy issues which could affect significantly the interests of the customers, shareholders, or employees of PG&E Corporation or its subsidiaries. The Public Policy Committee reviews the policies and practices of PG&E Corporation and its subsidiaries with respect to protection and improvement of the quality of the environment, charitable and community service organizations and activities, equal opportunity in hiring and promoting employees, and development of minority-owned and women-owned businesses as suppliers to PG&E Corporation and its subsidiaries. The Committee also reviews significant societal, governmental, and environmental trends and issues that may affect the operations of PG&E Corporation or its subsidiaries.

One member of the Committee, who is neither a current nor former employee of, nor current consultant to, PG&E Corporation or any of its subsidiaries, is appointed by the Board of Directors as the Committee's Chair.

ATTENDANCE AT BOARD AND COMMITTEE MEETINGS

Eight meetings of the PG&E Corporation Board of Directors and 22 meetings of the PG&E Corporation Board committees were held in 1999. Overall attendance of incumbent directors at such meetings was 95%. Individual attendance at meetings of the PG&E Corporation Board of Directors and Board committees was as follows:

R. A. Clarke 100%, H. M. Conger 93%, D. A. Coulter 95%, C. L. Cox 100%, W. S. Davila 88%, R. D. Glynn, Jr. 100%, D. M. Lawrence 77%, M. S. Metz 100%, C. E. Reichardt 95%, J. C. Sawhill 96%, and B. L. Williams 95%.

Six meetings of the Pacific Gas and Electric Company Board of Directors were held in 1999. Overall attendance of incumbent directors at these meetings was 97%. Individual attendance at the meetings was as follows: R. A. Clarke 100%, H. M. Conger 100%, D. A. Coulter 83%, C. L. Cox 100%, W. S. Davila 100%, R. D. Glynn, Jr. 100%, D. M. Lawrence 83%, M. S. Metz 100%, C. E. Reichardt 100%, J. C. Sawhill 100%, G. R. Smith 100%, and B. L. Williams 100%. There were no meetings of the Pacific Gas and Electric Company Executive Committee in 1999.

COMPENSATION OF DIRECTORS

Each director who is not an officer or employee of PG&E Corporation or Pacific Gas and Electric Company receives a quarterly retainer of $7,500 plus a fee of $1,000 for each Board or Board committee meeting attended. Non-employee directors who chair Board committees receive an additional quarterly retainer of $625. Under the Deferred Compensation Plan for Non-Employee Directors, directors of PG&E Corporation or Pacific Gas and Electric Company may elect to defer all or part of such compensation for varying periods. Directors who participate in the Deferred Compensation Plan may convert their deferred compensation into a number of common stock equivalents, the value of which is tied to the market value of PG&E Corporation common stock. Alternatively, participating directors may direct that their deferred compensation earn interest.

No director who serves on both the PG&E Corporation and Pacific Gas and Electric Company Boards and corresponding committees is paid additional compensation for concurrent service on Pacific Gas and Electric Company's Board or its committees, except that separate meeting fees are paid for each meeting of the Pacific Gas and Electric Company Board, or a Pacific Gas and Electric Company Board committee, that is not held concurrently or sequentially with a meeting of the PG&E Corporation Board or a corresponding PG&E Corporation Board committee. It is the usual practice of PG&E Corporation and Pacific Gas and Electric Company that meetings of the respective Boards and corresponding committees are held concurrently with each other and, therefore, that a single meeting fee is paid to each director for each set of meetings.

In addition, directors of PG&E Corporation or Pacific Gas and Electric Company are reimbursed for reasonable expenses incurred in attending Board or committee meetings. Directors of PG&E Corporation or Pacific Gas and Electric Company also are reimbursed for reasonable expenses incurred in connection with other activities undertaken on behalf of or for the benefit of PG&E Corporation or Pacific Gas and Electric Company.

Effective January 1, 1998, the PG&E Corporation Retirement Plan for Non-Employee Directors was terminated. Directors who had accrued benefits under the Plan were given a one-time option of receiving at retirement the benefit accrued through 1997, or of converting the present value of their accrued benefit into a PG&E Corporation common stock equivalent investment held in the Deferred Compensation Plan for Non-Employee Directors. The payment of frozen accrued retirement benefits, or distributions from the Deferred Compensation Plan attributable to the conversion of retirement benefits, cannot be made until the later of age 65 or retirement from the Board.

Under the Non-Employee Director Stock Incentive Plan, a component of the PG&E Corporation Long-Term Incentive Program, on the first business day of January of each year, each non-employee director of PG&E Corporation is entitled to receive stock-based grants with a total aggregate equity value of $30,000, composed of (1) restricted shares of PG&E Corporation common stock valued at $10,000 (based on the closing price of PG&E Corporation common stock on the first business day of the year), and (2) a combination of non-qualified stock options and common stock equivalents with a total equity value of $20,000, based on equity value increments of $5,000. The exercise price of stock options is equal to the market value of PG&E Corporation common stock (i.e., the closing price) on the date of grant. Restricted stock and stock options vest over the five-year period following the date of grant, except that restricted stock and stock options will vest immediately upon mandatory retirement from the Board at age 70, upon a director's death or disability, or in the event of a change in control. Common stock equivalents awarded are payable in the form of PG&E Corporation common stock only following a director's retirement from the Board, upon a director's death or disability, or in the event of a change in control. Unvested awards are forfeited if the recipient ceases to be a director for any other reason.

On January 4, 1999, each non-employee director received 323 restricted shares of PG&E Corporation common stock. Directors who were granted stock options received options to purchase 1,492 shares of PG&E Corporation common stock for each $5,000 increment of equity value (subject to the aggregate $20,000 limit) at an exercise price of $30.9375 per share, and directors who were granted common stock equivalents received 161.616 common stock equivalent units for each $5,000 increment of equity value (subject to the aggregate $20,000 limit).

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Katherine Quadros is a partner in the law firm of Quadros & Johnson. Ms. Quadros is the sister of E. James Macias, former Senior Vice President and General Manager of the Generation, Transmission, and Supply Business Unit of Pacific Gas and Electric Company. Quadros & Johnson was paid approximately $218,000 by Pacific Gas and Electric Company during 1999 in connection with providing certain legal services to that entity in the normal course of business. Such services are expected to continue to be provided to Pacific Gas and Electric Company in the future.

BOARD OF DIRECTORS RETIREMENT POLICY

It is the policy of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company that a person may not be designated as a candidate for election or re-election as a director after he or she has reached the age of 70.

SECURITY OWNERSHIP OF MANAGEMENT

The following table sets forth the number of shares of PG&E Corporation common stock beneficially owned (as defined in the rules of the Securities and Exchange Commission) as of January 31, 2000, by the respective directors of PG&E Corporation and Pacific Gas and Electric Company, the nominees for director, the current executive officers of PG&E Corporation and Pacific Gas and Electric Company named in the Summary Compensation Table on page 30, and all directors and executive officers of PG&E Corporation and Pacific Gas and Electric Company as a group. The number of shares shown for each such person, and for the directors, nominees for director, and executive officers as a group, constituted less than 1 percent of the outstanding shares of PG&E Corporation common stock. As of January 31, 2000, no director, nominee for director, or executive officer owned shares of any class of Pacific Gas and Electric Company securities. The table also sets forth common stock equivalents credited to the accounts of directors and executive officers under PG&E Corporation deferred compensation and equity plans.

NAME	(A) BENEFICIAL STOCK OWNERSHIP(1)(2)	(B) COMMON STOCK EQUIVALENTS(3)	(C) TOTAL
Richard A. Clarke(4)	130,047	4,177	134,224
Harry M. Conger(4)	7,984	2,397	10,381
David A. Coulter(4)	3,470	6,734	10,204
C. Lee Cox(4)	10,679	1,416	12,095
William S. Davila(4)	11,756	8,915	20,671
Robert D. Glynn, Jr.(4)	421,070	89,823	510,893
David M. Lawrence, MD(4)	10,458	2,169	12,627
Mary S. Metz(4)	7,425	682	8,107
Carl E. Reichardt(4)	5,729	11,829	17,558
John C. Sawhill(4)	28,384	6,950	35,334
Gordon R. Smith(5)	167,558	13,333	180,891
Barry Lawson Williams(4)	5,387	4,869	10,256
Scott W. Gebhardt(6)	164,677	6,893	171,570
P. Chrisman Iribe(6)	48,039	8,126	56,165
Thomas B. King(6)	4,326	45,088	49,414
Kent M. Harvey(7)	33,839	0	33,839
James K. Randolph(7)	44,972	132	45,104
Daniel D. Richard, Jr.(7)	23,273	411	23,684
Gregory M. Rueger(7)	72,450	0	72,450
All PG&E Corporation directors and executive officers as a group (21 persons)	1,392,226	322,785	1,715,011
All Pacific Gas and Electric Company directors and executive officers as a group (17 persons)	1,027,284	153,843	1,181,127

(1) Includes any shares held in the name of the spouse, minor children, or other relatives sharing the home of the director or executive officer and, in the case of executive officers, includes shares of PG&E Corporation common stock held in the defined contribution retirement plans maintained by PG&E Corporation, Pacific Gas and Electric Company, and their subsidiaries. Except as otherwise indicated below, the directors, nominees for director, and executive officers have sole voting and investment power over the shares shown. Voting power includes the power to direct the voting of the shares held, and investment power includes the power to direct the disposition of the shares held.

Also includes the following shares of PG&E Corporation common stock in which the beneficial owners share voting and investment power: Mr. Coulter 1,843 shares, Mr. Cox 6,912 shares, Mr. Davila 200 shares, Dr. Metz 3,886 shares, Mr. Smith 3,884 shares, all PG&E Corporation directors and executive officers as a group 19,881 shares, and all Pacific Gas and Electric Company directors and executive officers as a group 19,530 shares.

(2) Includes shares of PG&E Corporation common stock which the directors and executive officers have the right to acquire within 60 days of January 31, 2000, through the exercise of vested stock options granted under the PG&E Corporation Stock Option Plan, as follows: Mr. Clarke 125,000 shares, Mr. Coulter 1,749 shares, Mr. Glynn 402,492 shares, Dr. Lawrence 1,749 shares, Dr. Metz 1,312 shares, Mr. Reichardt 1,749 shares, Dr. Sawhill 1,312 shares, Mr. Smith 146,302 shares, Mr. Williams 1,749 shares, Mr. Gebhardt 141,135 shares, Mr. Iribe 31,867 shares, Mr. Harvey 29,201 shares, Mr. Randolph 44,868 shares, Mr. Richard 23,201 shares, Mr. Rueger 67,033 shares, all PG&E Corporation directors and executive officers as a group 1,136,788 shares, and all Pacific Gas and Electric Company directors and executive officers as a group 932,453 shares. The directors and executive officers have neither voting power nor investment power with respect to shares shown unless and until such shares are purchased through the exercise of the options, pursuant to the terms of the Stock Option Plan.

(3) Reflects the number of stock units purchased by officers and directors through salary and other compensation deferrals or awarded under equity compensation plans. The value of each stock unit is equal to the value of a share of PG&E Corporation common stock and fluctuates daily based on the market price of PG&E Corporation common stock. The directors and officers who own these stock units share the same market risk as PG&E Corporation shareholders, although they do not have voting rights with respect to these stock units.

(4) Mr. Clarke, Mr. Conger, Mr. Coulter, Mr. Cox, Mr. Davila, Mr. Glynn, Dr. Lawrence, Dr. Metz, Mr. Reichardt, Dr. Sawhill, and Mr. Williams are directors of both PG&E Corporation and Pacific Gas and Electric Company.

(5) Mr. Smith is a director and an executive officer of Pacific Gas and Electric Company, and also is an executive officer of PG&E Corporation. He is named in the Summary Compensation Table on page 30.

(6) Mr. Gebhardt, Mr. Iribe, and Mr. King are executive officers of PG&E Corporation named in the Summary Compensation Table on page 30.

(7) Mr. Harvey, Mr. Randolph, Mr. Richard, and Mr. Rueger are executive officers of Pacific Gas and Electric Company named in the Summary Compensation Table on page 30.

Item No. 2:
Ratification of Appointment of Independent Public Accountants

On the recommendation of the Audit Committee of PG&E Corporation, the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company have selected Deloitte & Touche as the independent public accountants to examine the financial statements of PG&E Corporation, Pacific Gas and Electric Company, and their respective subsidiaries for the year 2000. Deloitte & Touche is a major national accounting firm with substantial expertise in the energy and utility businesses. Deloitte & Touche has been employed to perform this function for PG&E Corporation and Pacific Gas and Electric Company since 1999. The firm of Arthur Andersen LLP was employed as independent public accountants from 1981 until the selection of Deloitte & Touche. During that period, good relations were maintained and there were no disagreements on accounting principles or practices, financial statement disclosure, or audit scope or procedures.

One or more representatives of Deloitte & Touche will be present at the annual meetings, and will be available to respond to appropriate questions.

The affirmative vote of a majority of the shares represented and voting on the proposal is required to ratify the appointment of the independent public accountants and the affirmative votes must constitute a majority of the required quorum. Abstentions will have the same effect as a vote against the proposal. Unless indicated to the contrary, properly executed proxies received by PG&E Corporation or Pacific Gas and Electric Company prior to or at the annual meetings will be voted for this proposal.

This appointment is not required to be submitted to a vote of the shareholders. If the shareholders should not ratify the appointment, the PG&E Corporation Audit Committee will investigate the reasons for rejection by the shareholders and each Board of Directors will reconsider the appointment.

THE BOARDS OF DIRECTORS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY RECOMMEND A VOTE FOR THE PROPOSAL TO RATIFY THE APPOINTMENT OF DELOITTE & TOUCHE.

IF YOU DO NOT HOLD ANY SHARES OF PG&E CORPORATION COMMON STOCK, YOU ARE NOT ENTITLED TO VOTE ON THE FOLLOWING TWO MANAGEMENT PROPOSALS.

Item Nos. 3 and 4:
Management Proposals

TO BE VOTED ON BY PG&E CORPORATION SHAREHOLDERS ONLY

ITEM NO. 3: MANAGEMENT PROPOSAL REGARDING PROPOSED AMENDMENTS TO PG&E CORPORATION'S ARTICLES OF INCORPORATION TO IMPLEMENT THE ELIMINATION OF A "SUPERMAJORITY VOTE" PROVISION

At the 1999 annual meeting of PG&E Corporation shareholders, a majority of the shares present and voting approved a shareholder proposal recommending that the Board of Directors reinstate simple majority voting for all matters submitted for shareholder approval. At present, the only matters that require more than a simple majority vote of shareholders are those matters covered by the Fair Price Provision contained in Article Eighth of the Restated Articles of Incorporation of PG&E Corporation. A copy of Article Eighth of the Restated Articles of Incorporation of PG&E Corporation as proposed to be amended is attached to this proxy statement. Capitalized terms used but not defined in this proxy statement shall have the meaning ascribed to such terms in Article Eighth.

PROPOSED AMENDMENTS TO THE FAIR PRICE PROVISION

Under the current Fair Price Provision, the approval of the holders of not less than 75 percent of the outstanding shares of voting stock of PG&E Corporation (a "supermajority vote") is required to effect a Business Combination involving PG&E Corporation or any of its subsidiaries and a Related Person or any of its Affiliates. A "Business Combination" is broadly defined to include (i) a merger or consolidation with a Related Person; (ii) a sale, lease, or exchange to a Related Person of any of the Corporation's assets having an aggregate fair market value of $100 million or more, or vice versa; (iii) an issuance, pledge, or transfer of the Corporation's securities to a Related Person in exchange for cash or other property having an aggregate fair market value of $100 million or more; (iv) a reclassification of securities, recapitalization, or other transaction which would directly or indirectly increase the voting power or the proportionate share of the Corporation's securities owned by a Related Person; or (v) any merger or consolidation of the Corporation with any of its Subsidiaries if, after the merger, the surviving entity's Articles of Incorporation do not contain the Fair Price Provision. A supermajority vote is not required if any such Business Combination is approved by the Board of Directors without counting the vote of any director who is not a Disinterested Director or if certain specified minimum price criteria and procedural requirements are satisfied.

The proposed amendments to the Fair Price Provision would replace the requirement for a supermajority vote with the requirement that a Business Combination be approved by the holders of a majority of PG&E Corporation's outstanding shares of voting stock (a "majority vote"). A majority vote requirement will make it easier for a Related Party or its Affiliate to effect a Business Combination involving PG&E Corporation or any of its subsidiaries, especially since a Related Party or its Affiliate may participate in the vote. As a consequence, a majority vote requirement may make it easier for the Related Party or its Affiliate to engage in transactions that are not necessarily in the best interests of all shareholders. Therefore, in order to protect shareholders against acts by a Related Party or its Affiliate that may be detrimental to shareholders as a whole, the Board of Directors has proposed that the Fair Price Provision be further amended to require that a proposed Business Combination, in addition to approval by a majority vote, also (i) be approved by the Board of Directors of PG&E Corporation without counting the vote of any director who is not a Disinterested Director or (ii) satisfy the existing minimum price and procedural requirements contained in the Fair Price Provision.

The proposed amendments also would change the definition of "Subsidiary" to include non-corporate entities. The proposed amendments also would delete the requirement that amendments to the Fair Price provision be approved by a supermajority vote.

EFFECTS OF THE AMENDED FAIR PRICE PROVISION

As amended, the Fair Price Provision is not intended to prevent or impede a third party from acquiring control of PG&E Corporation. Rather, the amended provision is intended to inhibit abusive conduct on the part of a Related Party or its Affiliate and is designed to protect shareholders against practices that do not treat all shareholders fairly and equally, including inadequate or coercive takeovers or self-dealing transactions. The proposed amendments to the Fair Price Provision will ensure that either a proposal resulting in a Business Combination will be scrutinized by the Disinterested Directors on the Board of Directors or will ensure that the consideration paid to shareholders in the Business Combination will be no less than the existing minimum price requirements set forth in the Fair Price Provision.

As amended, the Fair Price Provision may discourage an unsolicited offer that is favorable to a majority of shareholders but that does not otherwise (i) have the support of the Disinterested Directors on the Board of Directors or (ii) satisfy the fair price criteria and other procedural requirements contained in the Provision. To the extent that the amended Fair Price Provision makes the accomplishment of a Business Combination more difficult, it would make the removal of management more difficult even if such removal would be beneficial to the shareholders generally.

The Board of Directors of PG&E Corporation currently has no intention of soliciting a shareholder vote on any other proposals that might affect a possible change of control of PG&E Corporation. However, the Board of Directors of PG&E Corporation will continue to monitor developments in this area and in the future may recommend or pursue additional protective measures if it determines that such measures would be in the best interests of PG&E Corporation and its shareholders as a whole.

VOTE REQUIRED

The proposed amendments to the Fair Price Provision are permitted under California law and the rules of the New York Stock Exchange, the principal exchange upon which PG&E Corporation's stock is listed and traded. The proposed amendments will not become effective until (i) they are approved by the affirmative vote of the holders of a majority of the outstanding shares of voting stock of PG&E Corporation, and (ii) a certificate of amendment is filed with the California Secretary of State. Abstentions and broker non-votes will have the same effect as a vote against the proposal. Properly executed proxies received by PG&E Corporation prior to or at the annual meeting will be voted "FOR" the proposal, unless PG&E Corporation shareholders specify otherwise in their proxies.

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS THAT SHAREHOLDERS VOTE FOR THE FOREGOING AMENDMENTS TO THE ARTICLES OF INCORPORATION OF PG&E CORPORATION.

ITEM NO. 4: MANAGEMENT PROPOSAL REGARDING PROPOSED AMENDMENT TO PG&E CORPORATION'S ARTICLES OF INCORPORATION TO DECREASE THE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS

PG&E Corporation's Articles of Incorporation currently provide that the authorized number of directors shall be within a range of between nine and seventeen. The current authorized number of directors to be elected at the 2000 annual meeting is eleven. The Board of Directors of PG&E Corporation has unanimously approved an amendment to the Corporation's Articles of Incorporation to provide that the Board of Directors shall consist of not less than seven nor more than thirteen directors. The exact number of directors within the new authorized range will continue to be eleven until changed, within the limits specified in the Articles of Incorporation, by an amendment to the Bylaws adopted by the Board of Directors or the shareholders. The proposed amendment would not affect the number of directors to be elected at the 2000 annual meeting.

The Board of Directors believes that the current authorized number of directors is an appropriate size enabling the Board as a whole to function efficiently. The Board of Directors also believes that reducing the range of the minimum and maximum number of directors to between seven and thirteen is consistent with current corporate governance practices.

The first paragraph of Article Third of the Corporation's Articles of Incorporation currently provides:

> I: The Board of Directors of the Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17), as shall be prescribed in the Bylaws.

The Board of Directors proposes to amend the first paragraph of Article Third to read as follows:

> I: The Board of Directors of the Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13), as shall be prescribed in the Bylaws.

VOTE REQUIRED

The proposed amendment to the Articles of Incorporation will not become effective until (i) it is approved by the affirmative vote of the holders of a majority of the outstanding shares of voting stock of PG&E Corporation, and (ii) a certificate of amendment is filed with the California Secretary of State. Abstentions and broker non-votes will have the same effect as a vote against the proposal. Properly executed proxies received by PG&E Corporation prior to or at the annual meeting will be voted "FOR" the proposal, unless PG&E Corporation shareholders specify otherwise in their proxies.

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS THAT SHAREHOLDERS VOTE FOR THE FOREGOING AMENDMENT TO THE ARTICLES OF INCORPORATION OF PG&E CORPORATION.

IF YOU DO NOT HOLD ANY SHARES OF PG&E CORPORATION COMMON STOCK, YOU ARE NOT ENTITLED TO VOTE ON THE FOLLOWING SIX SHAREHOLDER PROPOSALS.

Item Nos. 5 to 10:
Shareholder Proposals

TO BE VOTED ON BY PG&E CORPORATION SHAREHOLDERS ONLY

The following proposals have been submitted by shareholders for action at the PG&E Corporation annual meeting. To be approved, each properly presented proposal must receive the affirmative vote of a majority of the PG&E Corporation shares represented and voting on the proposal, and the affirmative votes must constitute at least a majority of the required quorum. Abstentions will be counted in the number of shares represented and voting, and will have the same effect as a vote against the proposal. Broker non-votes with respect to a particular proposal will be counted for purposes of determining the presence or absence of a quorum, but will not be counted in the number of shares represented and voting on the proposal. Properly executed proxies received by PG&E Corporation prior to or at the annual meeting will be voted "AGAINST" these proposals, unless PG&E Corporation shareholders specify otherwise in their proxies.

ITEM NO. 5: SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS

Mr. John Chevedden, 2215 Nelson Avenue, No. 205, Redondo Beach, California 90278, on behalf of Mr. Ray T. Chevedden and Mrs. Veronica G. Chevedden, holders of 3,000 shares of PG&E Corporation common stock, has given notice of his intention to present the following proposal for action at the PG&E Corporation annual meeting:

"RESOLVED:

APPOINT INDEPENDENT DIRECTORS TO ALL KEY BOARD COMMITTEES

Adopt a policy that Independent Directors are appointed for all Key Board Committees to enhance management oversight (shareholder recommendation).

Key board committees include:

- Compensation
- Nomination &
- Audit Committees

These important oversight-committees require heightened independence, free of Directors with significant financial and management ties to PG&E. A director is deemed independent if his or her only non-trivial professional, financial or familial connection to the company or its CEO within the past 10 years is his or her directorship.

The following Directors profited directly or indirectly from their financial and management ties to PG&E (Source - 1998 PG&E proxy):

1. Dr. David Lawrence — CEO of Kaiser Health Plan
   - PG&E paid $23 million to Kaiser.
2. David Coulter — CEO of BankAmerica Corp. (until fired Oct. 1998)
   - PG&E paid $2.5 million to Bank of America
3. Lee Cox — Vice Chairman of AirTouch Communications
   - PG&E paid $1.5 Million to AirTouch.
4. Rebecca Morgan — CEO of JVSV Network
   - PG&E paid $100,000 to JVSV.
5. Richard Clark
   - Former PG&E CEO - tends to protect entrenched policies.

When this relationship was brought to the attention of shareholders in 1998, the company took the regressive step of deleting it from the 1999 proxy statement. The company was asked to reinstate this information in this proxy statement as a sign of its integrity.

Deleting information that points to needed changes is a disturbing act. It leads shareholders to believe that the company tends to conceal information on its problems rather than correct its problems.

Seven out of 15 seats on key committees are held by directors whose companies are PG&E customers. PG&E regularly pays more than $27 million annually to the employers of PG&E Directors.

Dr. Lawrence, whose company receives the largest payment, sits on the Compensation Committee that determines CEO pay. In 1998 the Compensation Committee more than doubled CEO pay - up 117% - Source:www.paywatch.org.

While paying $27 million to the employers of PG&E directors, PG&E substantially under-performed the S&P 500 and the Dow Jones Utilities Index. The graph on page 37 shows the PG&E under-performance in the most recent 5-year period. ADDITIONALLY, THE 39% DIVIDEND CUT OF 3 1/2 YEARS AGO HAS NOT BEEN RESTORED.

Dr. Lawrence's voice in determining CEO pay is a clear conflict of interest and divided loyalty. It sends the wrong message to PG&E's 20,000 employees: It implies that the divided loyalty is acceptable.

Under the watered-down PG&E definition of independence, a compensation committee stacked with directors whose employers have $27 million in annual contracts with PG&E, could "ensure independent oversight of management."

Institutional Shareholder services (www.cda.com/iss), a leading proxy analysis firm, said it is fundamental that a board is independent and therefore capable of objective oversight of top management.

APPOINT INDEPENDENT DIRECTORS TO ALL KEY BOARD COMMITTEES
VOTE YES ON ITEM NO. 5"

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

The Board of Directors believes this proposal is moot, as the Audit Committee and the Nominating and Compensation Committee of the Board of Directors are each composed entirely of independent directors as defined in the Corporation's corporate governance guidelines. Independent directors are defined in the guidelines as directors who are neither (a) current nor former employees of, nor consultants to, PG&E Corporation or its subsidiaries, nor (b) current nor former officers or employees of any other corporation on whose board of directors any officer of PG&E Corporation serves as a member. All the members of the Audit and Nominating and Compensation Committees are independent as defined in the guidelines. Further, another requirement of the guidelines specifies that 75 percent of the Board be composed of directors who are neither current nor former officers of PG&E Corporation or any of its subsidiaries, and the Corporation is in compliance with this requirement.

The Board does not believe that business relationships of the type cited by the proponent compromise the independence of the director. None of the named directors possesses a personal interest in the business transactions that would preclude the director's ability to exercise independent judgment or faithfully fulfill his or her fiduciary duties to PG&E Corporation's shareholders. The types of transactions cited by the proponent relate to ordinary business dealings between the named companies and PG&E Corporation, Pacific Gas and Electric Company (a subsidiary of PG&E Corporation), and their subsidiaries. Neither the Board, any Board committee, nor the director affiliated with the named business entity had any involvement in deciding whether to purchase goods or services from, or provide financial support to, the named business entity. Ordinary business transactions necessary to conduct the business of the Corporation and its subsidiaries are implemented by employees in the course of their employment, without direct Board involvement. For example, the dollar amount cited by the proponent which was paid by the Corporation and its subsidiaries to Kaiser Health Plan (the largest provider of healthcare services in California) represents premium payments directed by individual Corporation employees, who can choose among many healthcare providers. Neither the Board, any Board committee, Dr. Lawrence, nor Kaiser Health Plan has any influence over which health services provider an employee chooses.

The business relationships cited by the proponent were not required by Securities and Exchange Commission (SEC) rules to be disclosed in PG&E Corporation's 1999 and 2000 proxy statements, as these relationships do not meet the threshold for determining which relationships are significant enough to require proxy statement disclosure. Among other things, each of these business relationships represents less than 5 percent of the consolidated gross revenues of the Corporation and of each of the entities involved in the cited business relationships for the relevant fiscal year.

The PG&E Corporation Board of Directors believes that the composition of its Audit Committee and its Nominating and Compensation Committee (each consisting solely of independent directors) and the presence of a majority of independent directors on the Board pursuant to the Board's corporate governance policies ensure independent oversight of management.

Last year, of the Corporation's shares that were voted, approximately 71 percent voted against a similar proposal presented by this proponent.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

ITEM NO. 6: SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING

Mr. John Chevedden, 2215 Nelson Avenue, No. 205, Redondo Beach, California 90278, on behalf of Mrs. Ersilia N. Davis, 1488 San Pasqual Street, Pasadena, California 91106, holder of 200 shares of PG&E Corporation common stock, has given notice of his intention to present the following proposal for action at the PG&E Corporation annual meeting:

"RESOLVED:

CONFIDENTIAL SHAREHOLDER VOTING

The shareholders request that the board of directors adopt and implement a policy requiring all proxies, ballots and voting tabulations that identify how shareholders vote be kept confidential and the inspectors of election be independent and not the employees of the company.

SUPPORTING STATEMENT:

The confidential ballot is fundamental to the American political system. This protection ensures that voters are not subjected to:

1) Actual

2) Perceived or

3) Potential coercive pressure.

The fundamental principle of the confidential ballot should be applied to public corporations. While there is no inference that PG&E management uses coercion the existence of this possibility is sufficient to justify confidentiality.

Many major companies, such as Coca-Cola Co., Dow Chemical, Georgia-Pacific Corp., Gillette, Kimberly Clark, Louisiana Pacific, and Quaker Oats, use confidential voting.

The Investor Responsibility Research Center (IRRC) reported that confidential voting resolutions won 47% shareholder approval in 1998. IRRC surveyed 56 institutional investors and found that 75% said they consistently support confidential voting resolutions. PG&E is 51% owned by institutional shareholders.

Many shareholders believe confidential ownership is guaranteed when shares are held in street name. This is not always the case. Management has various means of determining actual ownership. For instance, proxy solicitors have elaborate databases that can match account numbers with the identity of some owners.

Moreover, why should shareholders be required to transfer their stock to street-name in an attempt to maintain confidentiality? This resolution is the only way to ensure a secret ballot for all shareholders irrespective of how they own their shares.

The confidential vote is an important step toward improving PG&E corporate governance.

WHY IMPROVE PG&E'S CORPORATE GOVERNANCE PRACTICES?

Fifty institutional investors, managing a total of $840 million, told McKinsey & Co. they would pay an 11% average premium for the stock of a company with good governance practices.

Why the big jump? Some investors said they believed that good governance would help boost performance over time. Others felt good governance decreases the risk of bad news - and when trouble occurs, they rebound faster.

BUSINESS WEEK Sept. 15, 1997

WHAT ISSUES HIGHLIGHT CONCERN ABOUT IMPROVING PG&E'S PERFORMANCE?

The 1998 directors, key-employees and consultants stock option plan has a total potential stock dilution of 8% - compared to 2% stock dilution for PG&E peer group.

Investor Responsibility Research Center
PG&E ANNUAL MEETING REPORT March 1999

PG&E stock price is down 17% for the year.

STANDARD & POORS Sept. 18, 1999

An administrative law judge proposed that Pacific Gas & Electric Co. be allowed to increase electric rates by less than a quarter of the $1 billion plus the company had originally demanded.

REUTERS Oct. 19, 1999

PG&E Corp. reported that third-quarter earnings fell nearly 13 percent.

REUTERS Oct. 15, 1999

ABN AMRO said it has cut by 18% its 1999 earnings estimates for PG&E Corp.

REUTERS Oct. 22, 1999

To improve corporate governance and company performance vote yes:

CONFIDENTIAL SHAREHOLDER VOTING
YES ON 6"

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

The Board of Directors supports policies and practices that maintain the confidentiality of the Corporation's proxy solicitation and balloting processes, and believes that the Corporation's current practices and policies enable shareholders to vote or give a proxy free from coercive pressure. The proposed confidential voting policy unnecessarily goes beyond the Corporation's existing practices, to restrict access to proxy, ballot, and vote tabulation information even if such access is legally required or otherwise is in the best interests of shareholders, such as when shareholders use their proxy cards as a vehicle for communicating with the Corporation or in the case of a proxy contest.

The Corporation does not use proxy or ballot information to identify how individual registered shareholders vote on particular issues. For years, the Corporation has used an independent inspector of elections and proxy tabulator, and has no plans to discontinue this practice. Shareholder proxies are returned directly to the independent proxy tabulator and are not reviewed by the Corporation. Confidentiality of voting decisions is preserved even when shareholders use the proxy card with its postage-paid return envelope to communicate with the Corporation on items of interest to them, such as historical account information, lost or stolen stock certificates, and other matters relating to the Corporation's business. In such cases, the independent tabulator maintains the confidentiality of the shareholder's vote by blocking out voting information on the proxy card prior to making a copy for the Corporation. Registered shareholders desiring additional assurances of confidentiality can register their shares in the name of a nominee, such as a stockbroker, bank, or other fiduciary. Since nominee holders do not disclose specific information regarding how the beneficial owners vote, confidentiality is preserved. Corporation employees who own stock through employee savings plans submit their votes through plan trustees, who are required to keep such information confidential and may not disclose such information to the Corporation.

The proposed confidential voting policy is not only unnecessary, but also is overly broad in that it contains no exemptions for proxy contests or situations in which disclosure of a shareholder's vote is legally required. In the case of a proxy contest, the proposed confidential voting policy would not apply to the third party that was soliciting proxies, yet would continue to apply to the Corporation, thereby giving the third party dissident an unfair advantage. The dissident would be able to view shareholder voting decisions and other information, and use that information to persuade individual shareholders to vote in the dissident's favor. This advantage is not only unfair, but could be detrimental to shareholders. In contesting the dissident's solicitation of proxies, the Corporation's Board of Directors has a legal obligation to act in the best interests of shareholders as a group, whereas the dissident would have no such obligation and would be free to act purely in his or her own self interest. Given the unfair advantage the dissident would gain from having access to voting information, the Board's ability to act in the best interests of shareholders would be hindered because the directors would not have the same access to that information. The proposed confidential voting policy also fails to permit exceptions when access to the shareholder voting information is required in response to federal or state legal requirements, or may be necessary to assist the Corporation in making a claim or defending against a claim.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

ITEM NO. 7: SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY

Mrs. Sydell B. Lemerman, 1855 Capistrano, Berkeley, California 94707, holder of 1,291 shares of PG&E Corporation common stock, has given notice of her intention to present the following proposal for action at the PG&E Corporation annual meeting:

"The shareholders of PG&E Corporation request the Board of Directors take the necessary steps to amend the company's governing instruments to adopt the following:

SHAREHOLDER DEMOCRACY

We live in a Democracy and our vote is our sacred right, yet PG&E Corp. denies that right when it comes to voting on company proposals.

"ABSTENTIONS WILL BE COUNTED IN THE NUMBER OF SHARES REPRESENTED AND VOTING, AND WILL HAVE THE SAME EFFECT AS A VOTE AGAINST THE PROPOSAL." page 21 - Joint notice of 1999 Annual Meetings - Joint Proxy Statement.

It is not in the law! It is not in the rules and regulations of the S.E.C! The Corporation is not mandated in overriding the shareholders majority vote if it so wishes, it has made its own ruling to do so.

A Yes vote means YES! A No vote means NO! An Abstention means I am present but I am not voting.

In defense of their stance, the Corporation likes to state that the SEC does not object and that all other companies do the same thing and therefore it is the right thing to do. WRONG!! A Yes vote means YES! A No vote means NO! An Abstention means neither yes or no and should NOT be counted. There is no other way.

Make your vote count and mean what you would like it to mean. YES, NO, NO VOTE!!!

Do not let the Corporation override our majority vote.

Vote YES for Shareholder Democracy."

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

The standard for determining whether shareholders have approved a matter submitted to them is controlled by the law of the state under which the corporation is incorporated. Although most publicly traded corporations are incorporated in Delaware, PG&E Corporation is incorporated in California. Under California law, most matters presented to shareholders are considered approved by shareholders if (1) the matter receives the affirmative vote of a majority of the shares "represented and voting," and if (2) the affirmative votes constitute at least a majority of the required quorum. SEC rules require that the proxy statement disclose the treatment of abstentions for each item to be voted upon by shareholders (except for the ratification of accountants). PG&E Corporation reports all affirmative votes, negative votes, and abstentions cast at each annual meeting in its first quarterly report on Form 10-Q filed with the SEC after the meeting.

Although California law does not specifically address the treatment of abstentions, other states do. For example, in Delaware where the majority of publicly traded corporations are incorporated, most matters submitted to shareholders are considered approved if the matter receives the affirmative vote of a majority of the shares "present and entitled to vote." Under Delaware law, abstentions are included in determining the number of shares "present and entitled to vote." In the absence of controlling authority under California law, PG&E Corporation has chosen to follow the law of Delaware and treat abstentions as shares "present and voting." PG&E Corporation believes that most investors in public corporations understand and expect this treatment of abstentions. The Corporation's proxy statement fully discloses this intended treatment so that a shareholder can make an informed decision in deciding whether to cast an abstention.

Further, California law requires that some matters submitted to shareholders, such as the proposed amendments of the Corporation's Articles of Incorporation under Item Nos. 3 and 4 above, be approved by the holders of a majority of the Corporation's outstanding shares. Under this approval standard, abstentions must be counted, since the abstaining shareholder's shares are outstanding. Therefore, the shareholder proposal would be legally impossible to implement, as it would require the Corporation to violate California law.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

ITEM NO. 8: SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING

Mr. Simon Levine, Trustee of the Simon Levine Living Trust, 960 Shorepoint Court, No. 306, Alameda, California 94501, holder of 5,706 shares of PG&E Corporation common stock, has given notice of his intention to present the following proposal for action at the PG&E Corporation annual meeting:

"The shareholders of PG&E Corporation request the Board of Directors take the necessary steps to amend the company's governing instruments to adopt the following:

REINSTATE CUMULATIVE VOTING FOR THE ELECTION OF PG&E CORP. DIRECTORS.

Cumulative Voting is of the utmost importance in order to let us, the shareholders, have a voice in the corporation. It is essential in letting us express ourselves as OWNERS.

When we are not in agreement with those in whom we put our faith and trust and we want them to know that in no uncertain terms, cumulative voting HELPS emphasize our concern by disavowing them and voting them out. It provides us the necessary tools to CHOOSE the directors we want.

It is to US, the owners of the company, to PROVIDE the leadership necessary to run the company well and profitably.

The following headlines from the San Francisco Chronicle illustrates some of the problems.

December Blackout no Fluke, PUC Says, reads one headline with the sub-head Staff report contends PG&E is error prone May 8, 1999

PG&E Fined for Poor Service in '95 Outage - June 25, 1999

PUC Urged To Continue PG&E PROBE - July 1, 1999

These examples, which are part of at least a half dozen negative articles, demonstrate in no uncertain terms that our board is not doing their job. This means that we, the owners, are not doing our job and that's SELECTING the right people to lead and guide this company properly.

The Corporation argument is that a small percentage of shareholders can elect a Director. True, but the board is doing the same with ONLY 13 Directors. The problem is that the Corporation is addressing the wrong item. What they should be concerned about is "why did this come up in the first place and what can we do to rectify it?"

It has been said that the beginning of a long trip is in taking the first step. Our first step is to make sure we vote for cumulative voting. It is our RIGHT and RESPONSIBILITY!!!

VOTE "YES" TO REINSTATE CUMULATIVE VOTING FOR THE ELECTION OF DIRECTORS."

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

PG&E Corporation believes that cumulative voting would erode shareholders' ability to elect directors who represent the interests of the shareholders as a whole.

Under cumulative voting, the total number of votes that each shareholder may cast in an election for directors is determined by multiplying the number of directors to be elected by the number of votes to which the shareholder's shares are entitled. Each shareholder may "cumulate" his or her votes by giving them all to one candidate, or may distribute his or her votes among as many candidates as the shareholder sees fit. Thus, where 11 directors are to be elected, a shareholder or group of shareholders holding less than 9 percent of the shares voting at the meeting would be capable of electing a director. This is true even if the holders of the remaining 91 percent of the voting shares are opposed to the election of that candidate and cast their votes to elect 11 other directors.

Cumulative voting would give a disproportionate and unfair weight to the votes cast by a minority shareholder or shareholders. The elimination of cumulative voting ensures that all directors are elected or removed only by a majority vote of shareholders voting in the election.

Last year, of the Corporation's shares that were voted, approximately 67 percent voted against a similar proposal presented by this proponent.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

ITEM NO. 9: SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK

Mr. Chris Rossi, P.O. Box 249, Boonville, California 95415, holder of 1,000 shares of PG&E Corporation common stock, has given notice of his intention to present the following proposal for action at the PG&E Corporation annual meeting:

> "Resolved, the stockholders request that the Board of Directors adopt the following policy:
>
> Beginning in the 2001 P.G.&E. Corporation fiscal year, total compensation of all members of the Board of Directors shall be at least 50% in common stock with a significant portion of each year's distribution to be held and not sold until their term as a director is ended.
>
> The directors enjoy a much greater impact on the conduct of the Corporation's business than do the shareholders and their compensation reflects that impact. However, there is no reason that they should not receive their compensation in a manner that would bring them closer to the shareholders, namely in common stock. In this manner, the value of their compensation is directly related to the performance of the corporation.
>
> Many corporations are compensating their directors with common stock without any loss of good prospective directors. There is no reason why P.G.&E. Corporation could not do the same.
>
> In October 21, 1999 of the S.F. Chronicle, the stock quote listed in the last 52 weeks had gone from $34 down to $22.19. Why should the Directors continue to earn the same compensation as if nothing happened while the shareholders suffer?
>
> Vote to compensate the directors in P.G.&E. common stock"

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

PG&E Corporation agrees that a portion of its directors' compensation should be composed of equity ownership in the Corporation. In December 1997, the Board of Directors, upon recommendation of the Nominating and Compensation Committee, approved amendments to PG&E Corporation's Long-Term Incentive Program to increase the portion of director pay that is equity-based. The Board believes these changes have further aligned the interests of directors with those of PG&E Corporation's shareholders, and provide a total director compensation package that is more competitive with that provided to directors of other energy and industrial companies. As a result of these changes, approximately 40 percent of total director pay is composed of stock-based compensation, an increase from less than 20 percent based on total director pay in 1997, prior to this change in policy. Please refer to the discussion of "Compensation of Directors" on page 9 for details concerning these changes.

However, the Corporation requires flexibility to set standards for director compensation and encourage such stock ownership through a variety of programs and incentives, and should not be limited to the strict standard set forth in the proposal. PG&E Corporation must be able to design and implement director compensation packages that can attract quality candidates. Requiring that a set percentage of compensation paid to directors be in the form of stock could discourage or prevent highly qualified individuals from serving on the Board in the future.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

ITEM NO. 10: SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS

Mr. Nick Rossi, P.O. Box 249, Boonville, California 95415, holder of 600 shares of PG&E Corporation common stock, has given notice of his intention to present the following proposal for action at the PG&E Corporation annual meeting:

> "Resolved, the stockholders request that the Board of Directors amend the company's governing instruments to adopt the following:
>
> Any severance benefits based on change of control of the company to directors, officers and (or) employees will be prohibited. The prohibition would not apply to existing contracts.
>
> It is the duty and responsibility of the Board of directors to oversee the general order of business toward providing a service and producing a profit.

If, in the course of doing their duties the Corporation is merged with another company, any severance benefits a director, officer or employee of the Corporation would receive would be in the same form of compensation the shareholders would receive, namely through stock dividends and increase in the value of the stock.

Vote to restrict severance benefits due to a merger or acquisition."

THE BOARD OF DIRECTORS OF PG&E CORPORATION RECOMMENDS A VOTE AGAINST THIS PROPOSAL.

The Board of Directors believes that, consistent with its duties to shareholders, the Board must retain the flexibility to consider and adopt appropriate mechanisms to deal with the uncertainty that a change in control situation would create. The Officer Severance Policy provides certain severance benefits if an executive officer covered by the policy is terminated without cause following a change in control, as discussed in the Executive Compensation section under "Termination of Employment and Change in Control Provisions."

The Board believes that reasonable provisions regarding severance benefits due to a change in control help allow senior management to remain focused on aggressively maximizing shareholder value during change in control situations, and not be distracted by concerns about the perceived need to remain on good terms with management of the acquiring entity. In addition, these types of change in control provisions are often part of a total compensation package offered to senior executives in most public companies. In order for PG&E Corporation to maintain a competitive compensation package to attract and retain the best qualified personnel, the Board believes that it needs the flexibility to adopt these types of change in control arrangements in the future if the Board determines it is appropriate and in the best interests of shareholders to do so.

For these reasons, the PG&E Corporation Board of Directors unanimously recommends that shareholders vote AGAINST this proposal.

NOMINATING AND COMPENSATION COMMITTEE REPORT ON COMPENSATION

PG&E Corporation is a national energy-based holding company, with businesses that include a diverse group of U.S.-based power generating, gas pipeline, and energy commodity trading and services businesses. PG&E Corporation also is the parent company of Pacific Gas and Electric Company, the regulated utility that delivers natural gas and electricity to one in every 20 Americans.

The Nominating and Compensation Committee of the PG&E Corporation Board of Directors (the "Committee") is responsible for overseeing and establishing executive compensation policies for PG&E Corporation and its subsidiaries, including Pacific Gas and Electric Company. The Committee also oversees the PG&E Corporation Long-Term Incentive Program and other employee benefit plans.

This report relates to the compensation paid to executive officers of PG&E Corporation and Pacific Gas and Electric Company during the fiscal year ended December 31, 1999. Compensation for the Chief Executive Officers of PG&E Corporation and Pacific Gas and Electric Company is approved by their respective Boards of Directors based on the recommendation of the Committee, which is composed of independent non-employee directors. In establishing the 1999 compensation of the Chief Executive Officers of PG&E Corporation and Pacific Gas and Electric Company, the respective Boards approved the recommendations of the Committee without modification. Compensation for all other PG&E Corporation and subsidiary officers is approved by the Committee, except that the Committee has delegated to the PG&E Corporation Chief Executive Officer the authority to approve compensation for certain officers of PG&E Corporation and its subsidiaries.

The Committee established compensation programs for 1999 to meet four objectives:

- To attract, retain, and motivate employees with the necessary mix of skills and experience for the development of PG&E Corporation's unregulated businesses, as well as the successful operation and expansion of its utility business.

- To minimize short-term and long-term costs and reduce corporate exposure to longer-term financial risk.

- To emphasize long-term incentives to further align shareholder and officers' interests and focus employees on enhancing total return for the Corporation's shareholders.

- To achieve maximum value from PG&E Corporation's collective workforce by designing compensation programs that facilitate movement by employees among the Corporation and its subsidiaries.

The Committee retains an independent consultant, Hewitt Associates, to help evaluate PG&E Corporation's compensation policies, to provide information about industry compensation practices and competitive pay levels, and to recommend compensation alternatives which are consistent with PG&E Corporation's compensation policies. Founded in 1940, Hewitt Associates is an international firm of consultants and actuaries specializing in the design and administration of employee compensation and benefit programs.

To meet its objective of paying compensation that is competitive with similar companies in 1999, the Committee selected a group consisting of 26 major energy and general industry companies (the "comparator group"). These companies were selected by the Committee because they are comparable to PG&E Corporation in size and because their approach to compensation emphasizes long-term incentives. Twenty-three of the 26 energy and general industry companies in the comparator group are included in the Standard & Poor's 500 Stock Index.

For 1999, the Committee established the following specific compensation targets for officers:

- A significant component of every officer's compensation should be tied directly to PG&E Corporation's performance for shareholders.

- Annual cash compensation (base salary and target annual incentive) and benefits should be equal to the average compensation paid to comparable officers of companies in the comparator group.

- Long-term incentives should be equal to the average compensation paid to comparable officers of companies in the comparator group, but provide the opportunity to pay out at the 75th percentile and higher for superior corporate performance.

Finally, in evaluating compensation program alternatives, the Committee considers the potential impact on PG&E Corporation of Section 162(m) of the Internal Revenue Code. Section 162(m) eliminates the deductibility of compensation over $1 million paid to the five highest paid executive officers of public corporations, excluding "performance-based compensation." Compensation programs will qualify as performance-based if (1) the performance targets are pre-established objective standards, (2) the programs have been approved by shareholders, and (3) there is no discretion to modify or alter payments after the performance targets have been established for the year.

The Committee believes that compensation paid under two of PG&E Corporation's three performance-based plans is deductible under Section 162(m). A substantial portion of the compensation paid to the executive officers of PG&E Corporation and Pacific Gas and Electric Company is paid under these qualifying performance-based plans. Although short-term compensation paid under PG&E Corporation's third performance-based plan will not be excluded from the deduction limit under Section 162(m), payments under this plan are conditioned primarily on the achievement of pre-established corporate financial objectives.

To the extent consistent with the Committee's overall policy of maintaining a competitive, performance-based compensation program, it is PG&E Corporation's intent to maintain the tax deductibility of the compensation which it pays. However, due to the restrictive nature of Section 162(m), technical compliance with its requirements can reduce or eliminate the value of using certain types of plans designed to provide incentives to increase shareholder value. As a result, although the Committee, in designing and maintaining a competitive incentive compensation program, will qualify as much of the compensation for deduction under Section 162(m) as is reasonably possible, such qualification is not a mandatory precondition to payments where technical compliance is inconsistent with the Committee's objective of incenting performance which results in increased shareholder value. It is anticipated that the amount of any tax deduction that may be forgone due to the impact of the Section 162(m) limit will be insignificant.

PRINCIPAL COMPONENTS OF COMPENSATION

BASE SALARY

PG&E CORPORATION BASE SALARY

PG&E Corporation's executive salaries are reviewed annually by the Committee based on (1) the results achieved by each individual, (2) expected corporate financial performance, measured by combined earnings per share, dividends, and stock price performance, and (3) changes in the average salaries paid to comparable executives by companies in the comparator group.

In setting the 1999 salary levels for PG&E Corporation's executive officers, the Committee's objective was that the overall average of the salaries paid to all officers as a group (including the Chief Executive Officer) should be approximately equal to the target competitive level.

Robert D. Glynn, Jr., Chief Executive Officer of PG&E Corporation, received an annual base salary of $800,000 in 1999. The salary level for Mr. Glynn is below the average salary of chief executive officers of the 26 companies in the comparator group. The overall average of the base salaries received by all PG&E Corporation officers (including Mr. Glynn) for 1999 was comparable to the average salary paid to all officers of the comparator group.

PACIFIC GAS AND ELECTRIC COMPANY BASE SALARY

Pacific Gas and Electric Company's executive salaries are reviewed annually by the Committee based on (1) the results achieved by each individual, (2) expected corporate financial performance, measured by combined earnings per share, dividends, and stock price performance, and (3) changes in the average salaries paid to comparable executives by companies in the comparator group.

In setting the 1999 salary levels for Pacific Gas and Electric Company's executive officers, the Committee's objective was that the overall average of the salaries paid to all officers as a group (including the Chief Executive Officer) should be approximately equal to the target competitive level.

Gordon R. Smith, Chief Executive Officer of Pacific Gas and Electric Company, received an annual base salary of $550,000 in 1999. The salary level for Mr. Smith is comparable to the average salary of senior executives in comparable positions in the 26 companies in the comparator group. The overall average of the base salaries received by all Pacific Gas and Electric Company officers (including Mr. Smith) for 1999 was comparable to the average salary paid to all officers of the comparator group.

SHORT-TERM INCENTIVES

PG&E CORPORATION ANNUAL INCENTIVE

The PG&E Corporation Short-Term Incentive Plan for 1999 was designed to provide annual incentives to all executive officers based largely on PG&E Corporation's success in meeting the 1999 corporate operating earnings per share objective. This objective emphasizes the impact of on-going results of operations by eliminating the effect of extraordinary gains or losses.

At the beginning of the year, target awards are set based on each executive's responsibilities and salary level. Final awards are determined by the Committee and may range from zero to twice the target, depending on the extent to which the corporate operating earnings per share objective is achieved. The Committee has discretion to modify or eliminate awards.

In 1999, PG&E Corporation achieved corporate operating earnings per share of $2.24 and the majority of PG&E Corporation executive officers received Short-Term Incentive Plan awards equal to 170 percent of their target awards.

PACIFIC GAS AND ELECTRIC COMPANY ANNUAL INCENTIVE

The Pacific Gas and Electric Company Short-Term Incentive Plan for 1999 was designed to provide annual incentives to all executive officers based on meeting financial, service, and other measures of the Company, as well as those of specific business units and departments.

At the beginning of the year, target awards are set based on each executive's responsibilities and salary level. Final awards are determined by the Committee and may range from zero to twice the target, depending on the extent to which the stated objectives are achieved. The Committee has discretion to modify or eliminate awards.

In 1999, Pacific Gas and Electric Company executives received Short-Term Incentive Plan awards ranging from 133 percent to 171 percent of their target awards.

STOCK OPTIONS IN LIEU OF SHORT-TERM INCENTIVE PLAN AWARDS

In 1998, to further increase the officers' ability to align their individual economic interests with those of the Corporation and its shareholders, the Committee adopted a program whereby eligible officers could elect to convert up to 50 percent of the award they otherwise would be entitled to receive under their respective Short-Term Incentive Plan, and instead, receive stock options under the PG&E Corporation Stock Option Plan described below.

LONG-TERM INCENTIVES

PG&E CORPORATION LONG-TERM INCENTIVE PROGRAM. The PG&E Corporation Long-Term Incentive Program permits various stock-based incentive awards to be granted to executive officers and other employees of the Corporation and its subsidiaries. The Stock Option Plan and the Performance Unit Plan (each of which is a component of the Long-Term Incentive Program) provide incentives based on PG&E Corporation's financial performance over time.

PG&E CORPORATION STOCK OPTION PLAN. The Stock Option Plan provides incentives based on PG&E Corporation's ability to sustain financial performance over a 3- to 10-year period. Under the Plan, officers, managers, and other key employees of PG&E Corporation and its subsidiaries receive stock options based on their responsibilities and position. These options allow them to purchase a certain number of shares of PG&E Corporation common stock at the market price on the date of grant (typically the first business day of each year). Generally, optionees must hold the options for at least two full years and exercise them within 10 years. Options granted in lieu of Short-Term Incentive Plan awards, as discussed above, will be vested immediately, although the options may not be exercised for at least one year after the date of grant. PG&E Corporation does not reprice or change the terms of options once they have been granted.

At the Committee's discretion, stock options may be granted with tandem "stock appreciation rights" which have vesting periods and exercise guidelines that are similar to the options. These rights allow option-holders to surrender their options when they have vested and receive a cash payment equal to the difference between the exercise price and the current market price. No stock appreciation rights have been granted since 1991.

Stock options also may be granted with or without tandem "dividend equivalents" which provide for credits to be made to a dividend equivalent account equal to the current common stock dividend multiplied by the recipient's unexercised options. For options granted with dividend equivalents, option-holders are entitled to receive the amounts accumulated in their dividend equivalent account only when, and to the extent that, the underlying options or stock appreciation rights are exercised. If a stock appreciation right is exercised, the option-holder receives the associated dividend equivalent only if the stock price has appreciated by at least 5 percent per year from the date of grant or by at least 25 percent if the options have been held for more than five years. In June 1997, the Committee adopted the policy that future stock option grants will not include dividend equivalents, and no such grants with dividend equivalents have been made since that time.

The size of the stock option grant for each executive officer of PG&E Corporation and Pacific Gas and Electric Company in 1999 was determined by the Committee based on the Committee's objectives of paying target total compensation at the average total compensation of the companies in the comparator group, and of tying a substantial component of target total compensation directly to financial performance for shareholders. In making stock option grants, the size of each executive officer's stock option grant was determined primarily based on the compensation objectives described above.

PG&E CORPORATION PERFORMANCE UNIT PLAN. The Performance Unit Plan provides incentives based on PG&E Corporation's ability to sustain superior total returns for shareholders (dividends plus stock price appreciation) over a three-year period. Under the Plan, officers of PG&E Corporation and its subsidiaries receive performance units reflecting their level of responsibility. One-third of the units vest each year. At the end of each year, the number of vested performance units is increased or decreased based on PG&E Corporation's three-year total return for shareholders (dividends plus stock price appreciation) as compared with that of the 49 other largest energy-based companies in the nation. Each officer receives an incentive payment equal to the final number of vested units multiplied by the average market price of PG&E Corporation common stock during the 30 calendar day period prior to the end of the year.

In determining Performance Unit Plan results for a given year, PG&E Corporation's corporate performance in the current year is weighted at 60 percent, the performance in the prior year at 25 percent, and the performance in the year before that at 15 percent. Each time a cash dividend is declared on PG&E Corporation common stock, an amount equal to the cash dividend per share multiplied by the number of units held by a recipient will be accrued on behalf of the recipient and, at the end of the year, the amount of accrued dividend equivalents will be increased or decreased by the same percentage used to increase or decrease the recipient's number of vested performance units for the year.

For the three years ended December 31, 1999, PG&E Corporation's total shareholder return had a weighted average ranking of 35th among the 50 largest energy-based companies in the nation. Based on this ranking, officers received awards that were based on 40 percent of the number of vested units.

EXECUTIVE STOCK OWNERSHIP PROGRAM. Effective January 1, 1998, the Committee adopted the Executive Stock Ownership Program which contains certain stock ownership targets for executives to be achieved within five years after becoming an executive officer. The targets are set as a multiple of the executive's base salary and vary according to the executive's level of responsibility within the Corporation. The executive stock ownership targets are as follows: three times base salary for the Chief Executive Officer of PG&E Corporation; two times base salary for heads of the Corporation's lines of business, and the Chief Financial Officer and the General Counsel of PG&E Corporation; and one and one-half times base salary for the Senior Vice Presidents of PG&E Corporation. To the extent an executive officer achieves and maintains the stock ownership targets within the first three years of becoming an executive officer, the executive officer will be entitled to receive additional common stock equivalents (called Special Incentive Stock Ownership Premiums or SISOPs) to be credited to the deferred compensation portion of his or her Supplemental Retirement Savings Plan account balance. The additional common stock equivalents vest three years after the date of grant, subject to accelerated vesting in accordance with the Officer Severance Policy and upon a change in control of the Corporation. The additional common stock equivalents are subject to forfeiture if the executive fails to maintain the applicable stock ownership target.

BENEFITS

Benefit plans are designed to meet the individual needs of PG&E Corporation and its subsidiaries and to permit portability of benefits among the Corporation and its subsidiaries. Tax-deferred savings arrangements provide employees with an opportunity to supplement their retirement income through employee and matching contributions by PG&E Corporation or one of its subsidiaries. PG&E Corporation also provides excess retirement benefits for its executive officers based on salary and incentive compensation.

The defined contribution benefit plans of PG&E Corporation and its subsidiaries permit participants in those plans to direct the investment of their contributions into PG&E Corporation common stock, providing another opportunity for executive officers to increase their proprietary interest in PG&E Corporation. The PG&E Corporation Supplemental Retirement Savings Plan also permits the executives who participate in the plan to direct that the return on their deferred compensation be tied directly to the performance of PG&E Corporation common stock.

SUMMARY

We, the members of the Nominating and Compensation Committee of the Board of Directors of PG&E Corporation, believe that the compensation programs of PG&E Corporation and Pacific Gas and Electric Company are successful in attracting and retaining qualified employees and in tying compensation directly to performance for shareholders and service to customers. We will continue to monitor closely the effectiveness and appropriateness of each of the components of compensation to reflect changes in the business environment of PG&E Corporation and Pacific Gas and Electric Company.

March 13, 2000

NOMINATING AND COMPENSATION COMMITTEE OF THE BOARD OF DIRECTORS OF PG&E CORPORATION

Carl E. Reichardt, Chair
David A. Coulter
C. Lee Cox
David M. Lawrence, MD
John C. Sawhill

SUMMARY COMPENSATION TABLE

[THIS TABLE SUMMARIZES THE PRINCIPAL COMPONENTS OF COMPENSATION PAID TO THE CHIEF EXECUTIVE OFFICERS AND THE OTHER MOST HIGHLY COMPENSATED EXECUTIVE OFFICERS OF PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY DURING THE PAST YEAR.]

		ANNUAL COMPENSATION			LONG-TERM COMPENSATION		
					AWARDS	PAYOUTS	
(A) NAME AND PRINCIPAL POSITION	(B) YEAR	(C) SALARY ($)	(D) BONUS ($)(1)	(E) OTHER ANNUAL COMPEN-SATION ($)(2)	(F) SECURITIES UNDERLYING OPTIONS/SARS (# OF SHARES)	(G) LTIP PAYOUTS ($)(3)	(H) ALL OTHER COMPEN-SATION ($)(4)
Robert D. Glynn, Jr., Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation; Chairman of the Board of Pacific Gas and Electric Company	1999	$800,000	$1,224,000	$23,181	300,000	$176,204	$ 36,780
	1998	700,000	931,350(5)	42,180	235,000	452,858	32,280
	1997	533,334	217,074	39,525	268,000	408,796	24,780
Scott W. Gebhardt, Senior Vice President of PG&E Corporation; President and Chief Executive Officer of PG&E Energy Services Corporation	1999	$425,000	$ 249,688	$ 9,360	122,500	$ 74,436	$112,232
	1998	375,000	179,250	25,588	126,400	145,580	170,858
	1997	281,250	175,000	39,355	148,500	66,202	279,258
P. Chrisman Iribe, Senior Vice President of PG&E Corporation; President and Chief Operating Officer of PG&E Generating	1999	$350,000	$ 330,750	$ 5,456	106,500	$ 44,214	$ 48,672
	1998	296,400	283,062	7,937	50,600	82,843	30,780
	1997	142,500	102,600	6,480	45,000	52,961	27,235
Thomas B. King,(6) Senior Vice President of PG&E Corporation; President and Chief Operating Officer of PG&E Gas Transmission	1999	$350,000	$ 336,875	$12,049	100,000	$ 59,325	$ 76,487
	1998	29,167	0	0	50,000	93,627	200,000
Gordon R. Smith, Senior Vice President of PG&E Corporation; President and Chief Executive Officer of Pacific Gas and Electric Company	1999	$550,000	$ 460,075	$10,054	122,500	$ 74,436	$ 25,360
	1998	425,000	410,338	16,328	126,400	173,662	19,735
	1997	327,917	102,743	12,718	133,500	145,644	15,366
Kent M. Harvey, Senior Vice President, Chief Financial Officer, Controller, and Treasurer of Pacific Gas and Electric Company	1999	$245,000	$ 185,551	$ 4,172	46,700	$ 36,654	$ 23,083
	1998	220,000	189,486	8,465	50,600	96,885	9,900
	1997	185,000	134,047	8,250	14,500	92,709	8,325
James K. Randolph, Senior Vice President and General Manager - Transmission, Distribution, and Customer Service of Pacific Gas and Electric Company	1999	$290,000	$ 221,850	$ 4,172	46,700	$ 36,654	$ 13,050
	1998	260,000	213,174	8,465	50,600	96,885	11,700
	1997	220,000	104,564	8,700	30,000	92,709	9,919
Daniel D. Richard, Jr., Senior Vice President, Public Affairs of Pacific Gas and Electric Company; Vice President, Governmental Relations of PG&E Corporation	1999	$245,000	$ 182,905	$ 4,304	53,300	$ 37,434	$ 5,714
	1998	220,000	186,912	7,937	50,600	82,843	3,600
	1997	192,500	130,160	6,480	14,500	52,988	0
Gregory M. Rueger, Senior Vice President and General Manager - Nuclear Power Generation of Pacific Gas and Electric Company	1999	$290,000	$ 222,633	$ 4,172	46,700	$ 36,654	$ 14,743
	1998	278,000	230,684	8,993	50,600	110,926	13,260
	1997	268,000	128,833	10,920	33,500	132,430	12,810

SUMMARY COMPENSATION TABLE
CONTINUED

(1) Represents payments received or deferred from 1998 through 2000 for achievement of corporate and organizational objectives from 1997 through 1999, under the Short-Term Incentive Plan.

(2) Amounts reported consist of (i) reportable officer benefit allowances, (ii) payments of related taxes, and (iii) dividend equivalent payments on performance units under the Performance Unit Plan.

(3) Represents payments received or deferred in 2000, 1999, and 1998 for achievement of corporate performance objectives for the periods 1997 through 1999, 1996 through 1998, and 1995 through 1997, respectively, under the Performance Unit Plan.

(4) Amounts reported for 1999 consist of: (i) contributions to defined contribution retirement plans (Mr. Glynn $7,200, Mr. Gebhardt $16,000, Mr. Iribe $16,000, Mr. King $16,000, Mr. Smith $7,200, Mr. Harvey $7,200, Mr. Randolph $7,200, Mr. Richard $3,600, and Mr. Rueger $7,200), (ii) premiums on indemnity policies to secure the payment of benefits under the Supplemental Executive Retirement Plan and the Deferred Compensation Plan (Mr. Glynn $780, Mr. Smith $610, and Mr. Rueger $750), (iii) contributions received or deferred under excess benefit arrangements associated with defined contribution retirement plans (Mr. Glynn $28,800, Mr. Gebhardt $79,192, Mr. Iribe $32,672, Mr. King $19,000, Mr. Smith $17,550, Mr. Harvey $3,825, Mr. Randolph $5,850, Mr. Richard $1,913, and Mr. Rueger $5,850), (iv) above market interest on deferred compensation (Mr. Harvey $12,058, Mr. Richard $201, and Mr. Rueger $943), and (v) one-time payments, including relocation allowances (Mr. Gebhardt $17,040 and Mr. King $41,487).

(5) This amount includes $465,675 which was used by Mr. Glynn to purchase 123,324 stock options on March 1, 1999, under the Stock Option Purchase Program. These options have an exercise price of $31.4375 per share and expire on March 2, 2009.

(6) Mr. King was not employed by PG&E Corporation or Pacific Gas and Electric Company in 1997.

OPTION/SAR GRANTS IN 1999

[THIS TABLE SUMMARIZES THE DISTRIBUTION AND THE TERMS AND CONDITIONS OF STOCK OPTIONS GRANTED TO THE EXECUTIVE OFFICERS NAMED IN THE SUMMARY COMPENSATION TABLE DURING THE PAST YEAR.]

INDIVIDUAL GRANTS					GRANT DATE VALUE
(A)	(B)	(C)	(D)	(E)	(F)
NAME	NUMBER OF SECURITIES UNDERLYING OPTIONS/SARS GRANTED (#)(1)(2)	% OF TOTAL OPTIONS/SARS GRANTED TO EMPLOYEES IN 1999(2)	EXERCISE OR BASE PRICE ($/SH)(3)	EXPIRATION DATE(4)	GRANT DATE PRESENT VALUE ($)(5)
Robert D. Glynn, Jr.	300,000	4.26%	$30.9375	01-05-2009	$1,257,000
Scott W. Gebhardt	122,500	1.74%	$30.9375	01-05-2009	$ 513,275
P. Chrisman Iribe	106,500	1.51%	$30.9375	01-05-2009	$ 446,235
Thomas B. King	100,000	1.42%	$30.9375	01-05-2009	$ 419,000
Gordon R. Smith	122,500	1.74%	$30.9375	01-05-2009	$ 513,275
Kent M. Harvey	46,700	.66%	$30.9375	01-05-2009	$ 195,673
James K. Randolph	46,700	.66%	$30.9375	01-05-2009	$ 195,673
Daniel D. Richard, Jr.	53,300	.76%	$30.9375	01-05-2009	$ 223,327
Gregory M. Rueger	46,700	.66%	$30.9375	01-05-2009	$ 195,673

(1) All options granted to executive officers in 1999 are exercisable as follows: one-third of the options may be exercised on or after the second anniversary of the date of grant, two-thirds on or after the third anniversary, and 100 percent on or after the fourth anniversary, provided that options will vest immediately upon the occurrence of certain events. No options were accompanied by tandem dividend equivalents.

(2)`No stock appreciation rights (SARs) have been granted since 1991.

(3) The exercise price is equal to the closing price of PG&E Corporation common stock on the date of grant.

(4) All options granted to executive officers in 1999 expire 10 years and one day from the date of grant, subject to earlier expiration in the event of the officer's termination of employment with PG&E Corporation, Pacific Gas and Electric Company, or one of their respective subsidiaries.

(5) Estimated present values are based on the Black-Scholes Model, a mathematical formula used to value options traded on stock exchanges. The Black-Scholes Model considers a number of factors, including the expected volatility and dividend rate of the stock, interest rates, and time of exercise of the option. The following assumptions were used in applying the Black-Scholes Model to the 1999 option grants shown in the table above: volatility of 16.79%, risk-free rate of return of 4.64%, dividend yield of $1.20 (the annual dividend rate on the grant date), and an exercise date five years after the date of grant. The ultimate value of the options will depend on the future market price of PG&E Corporation common stock, which cannot be forecast with reasonable accuracy. That value will depend on the future success achieved by employees for the benefit of all shareholders. The estimated grant date present value for the options shown in the table was $4.19 per share.

AGGREGATED OPTION/SAR EXERCISES IN 1999 AND YEAR-END OPTION/SAR VALUES

[THIS TABLE SUMMARIZES EXERCISES OF STOCK OPTIONS AND TANDEM STOCK APPRECIATION RIGHTS (GRANTED IN PRIOR YEARS) BY THE EXECUTIVE OFFICERS NAMED IN THE SUMMARY COMPENSATION TABLE DURING THE PAST YEAR, AS WELL AS THE NUMBER AND VALUE OF ALL UNEXERCISED OPTIONS HELD BY SUCH NAMED EXECUTIVE OFFICERS AT THE END OF 1999.]

(A) NAME	(B) SHARES ACQUIRED ON EXERCISE (#)	(C) VALUE REALIZED ($)	(D) NUMBER OF SECURITIES UNDERLYING UNEXERCISED OPTIONS/SARS AT END OF 1999 (#) (EXERCISABLE/ UNEXERCISABLE)	(E) VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARS AT END OF 1999 ($)(1) (EXERCISABLE/ UNEXERCISABLE)
Robert D. Glynn, Jr.	0	$ 0	153,834/852,990	$0/$0
Scott W. Gebhardt	0	0	49,501/347,899	0/ 0
P. Chrisman Iribe	0	0	15,000/187,100	0/ 0
Thomas B. King	0	0	0/150,000	0/ 0
Gordon R. Smith	0	0	85,169/345,731	0/ 0
Kent M. Harvey	0	0	9,334/108,466	0/ 0
James K. Randolph	12,000	120,355	19,834/118,799	0/ 0
Daniel D. Richard, Jr.	0	0	4,834/113,566	0/ 0
Gregory M. Rueger	5,334	57,674	31,167/127,465	0/ 0

(1) Based on the difference between the option exercise price (without reduction for the amount of accrued dividend equivalents, if any) and a fair market value of $20.50, which was the closing price of PG&E Corporation common stock on December 31, 1999.

LONG-TERM INCENTIVE PROGRAM--AWARDS IN 1999

[THIS TABLE SUMMARIZES THE LONG-TERM INCENTIVE AWARDS MADE TO THE EXECUTIVE OFFICERS NAMED IN THE SUMMARY COMPENSATION TABLE DURING THE PAST YEAR.]

	AWARDS		ESTIMATED FUTURE PAYOUTS UNDER NON-STOCK PRICE-BASED PLANS		
(A) NAME	(B) NUMBER OF SHARES, UNITS, OR OTHER RIGHTS	(C) PERFORMANCE OR OTHER PERIOD UNTIL MATURATION OR PAYOUT	(D) THRESHOLD ($ OR #)(3)	(E) TARGET ($ OR #)(3)	(F) MAXIMUM ($ OR #)(3)
Robert D. Glynn, Jr.	20,000(1) 18,485(2)	3 years 3 years	0 units	20,000 units	40,000 units
Scott W. Gebhardt	10,800(1) 6,593(2)	3 years 3 years	0 units	10,800 units	21,600 units
P. Chrisman Iribe	6,800(1)	3 years	0 units	6,800 units	13,600 units
Thomas B. King	11,000(1)	3 years	0 units	11,000 units	22,000 units
Gordon R. Smith	10,800(1) 1,899(2)	3 years 3 years	0 units	10,800 units	21,600 units
Kent M. Harvey	4,125(1)	3 years	0 units	4,125 units	8,250 units
James K. Randolph	4,125(1)	3 years	0 units	4,125 units	8,250 units
Daniel D. Richard, Jr.	4,400(1)	3 years	0 units	4,400 units	8,800 units
Gregory M. Rueger	4,125(1)	3 years	0 units	4,125 units	8,250 units

(1) Represents performance units granted under the Performance Unit Plan. The units vest one-third in each of the three years following the grant year, and are earned over the vesting period based on PG&E Corporation's three-year total annual shareholder return (dividends plus stock price appreciation) as compared with that achieved by the 49 other largest domestic energy utilities. This performance target may be adjusted during the vesting period, at the sole discretion of the Nominating and Compensation Committee, to reflect extraordinary events beyond management's control. In determining PG&E Corporation's total annual shareholder return relative to the 49 other utilities, third-year performance is weighted at 60 percent, second-year performance at 25 percent, and first-year performance at 15 percent. Each time a cash dividend is declared on PG&E Corporation common stock, an amount equal to the cash dividend per share multiplied by the number of units held by a recipient will be accrued on behalf of the recipient and, at the end of the year, the amount of accrued dividend equivalents will be increased or decreased by the same percentage used to increase or decrease the recipient's number of vested performance units for the year.

(2) Represents common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) earned under the Executive Stock Ownership Program. SISOPs are earned by eligible officers who achieve and maintain minimum PG&E Corporation common stock ownership levels as set by the Nominating and Compensation Committee. Of the officers named in the Summary Compensation Table on page 30, only Messrs. Glynn, Gebhardt, Iribe, King, and Smith are eligible officers. Each SISOP represents a share of PG&E Corporation common stock, which vests at the end of three years. Units can be forfeited prior to vesting if an eligible officer fails to maintain his minimum stock ownership level. Upon retirement or termination, vested SISOPs are distributed in the form of an equivalent number of shares of PG&E Corporation common stock.

(3) Payments are determined by multiplying the number of units earned in a given year by the average market price of PG&E Corporation common stock for the last 30 calendar day period of the year.

RETIREMENT BENEFITS

PG&E Corporation and Pacific Gas and Electric Company provide retirement benefits to some of the executive officers named in the Summary Compensation Table on page 30. During 1999, the benefit formula for eligible executive officers was 1.6 percent of the average of the three highest combined salary and annual incentive awards during the last 10 years of service multiplied by years of credited service. Effective January 1, 2000, the multiplier was increased from 1.6 percent to 1.7 percent. As of December 31, 1999, the estimated annual retirement benefits for the most highly compensated executive officers, assuming credited service to age 65, are as follows: Mr. Glynn $451,080, Mr. Smith $454,472, Mr. Harvey $233,609, Mr. Randolph $254,013, Mr. Richard $103,548, and Mr. Rueger $309,605. The amounts shown are single life annuity benefits and would not be subject to any Social Security offsets.

TERMINATION OF EMPLOYMENT AND CHANGE IN CONTROL PROVISIONS

The PG&E Corporation Officer Severance Policy, which covers most officers of PG&E Corporation and its subsidiaries, including the executive officers named in the Summary Compensation Table, provides benefits if a covered officer is terminated without cause. In most situations, benefits under the policy include (i) a lump sum payment of one and one-half or two times annual base salary and target Short-Term Incentive Plan award (the applicable severance multiple being dependent on an officer's level), (ii) continued vesting of equity-based awards for 18 months or two years after termination (depending on the applicable severance multiple), (iii) accelerated vesting of up to two-thirds of the common stock equivalents awarded under the Executive Stock Ownership Program (depending on an officer's level), and (iv) payment of health care insurance premiums for 18 months or two years after termination (depending on the applicable severance multiple). In lieu of all or a portion of the lump sum payment, a terminated officer who is covered by PG&E Corporation's Supplemental Executive Retirement Plan can elect additional years of service and/or age for purposes of calculating pension benefits. Effective July 21, 1999, the policy was amended to provide covered officers with alternative benefits that apply upon actual or constructive termination following a change in control or potential change in control. According to the policy, a "change in control" occurs upon (i) the acquisition of 20 percent or more of the Corporation's outstanding voting securities by a single entity or person, (ii) a change in the directors who constitute a majority of the Board of Directors over a two-year period, unless the new directors were nominated by at least two-thirds of the Board of Directors who were directors at the beginning of the two-year period, or (iii) shareholder approval of certain corporate transactions. Constructive termination includes certain changes to a covered officer's responsibilities. In the event of a change in control or potential change in control, the policy provides for a lump payment of the sum of (i) unpaid base salary earned through the termination date, (ii) target Short-Term Incentive Plan award calculated for the fiscal year in which termination occurs ("Target Bonus"), (iii) any accrued but unpaid vacation pay, and (iv) three times the sum of Target Bonus and the officer's annual base salary in effect immediately before either the date of termination or the change in control, whichever base salary is greater. Change in control termination benefits also include reimbursement of excise taxes levied upon the severance benefit pursuant to Internal Revenue Code Section 4999.

The Long-Term Incentive Program (LTIP) permits the grant of various types of stock-based incentive awards, including awards granted under the Stock Option Plan, the Performance Unit Plan, and the Non-Employee Director Stock Incentive Plan. The LTIP and the component plans provide that, upon the occurrence of a change in control, (1) any time periods relating to the exercise or realization of any incentive award (including common stock equivalents awarded under the Executive Stock Ownership Program) will be accelerated so that such award may be exercised or realized in full immediately upon the change in control, (2) all shares of restricted stock will immediately cease to be forfeitable, and (3) all conditions relating to the realization of any stock-based award will terminate immediately. Under the LTIP, a "change in control" will be deemed to have occurred if any of the following occurs: (1) any "person" (as such term is used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, but excluding any benefit plan for employees or any trustee, agent, or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the beneficial owner of securities of PG&E Corporation representing 20 percent or more of the combined voting power of PG&E Corporation's then outstanding securities, (2) during any two consecutive years, individuals who at the beginning of such a period constitute the Board of Directors cease for any reason to constitute at least a majority of the Board of Directors, unless the election, or the nomination for election by the shareholders of the Corporation, of each new director was approved by a vote of at least two-thirds of the directors then still in office who were directors at the beginning of the period, or (3) the shareholders of the Corporation shall have approved (i) any consolidation or merger of the Corporation other than a merger or consolidation that would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent of such surviving entity) at least 70 percent of the combined voting power of the Corporation, such surviving entity, or the parent of such surviving entity outstanding immediately after the merger or consolidation, (ii) any sale, lease, exchange, or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Corporation, or (iii) any plan or proposal for the liquidation or dissolution of the Corporation. For purposes of this definition, the term "combined voting power" means the combined voting power of the then outstanding voting securities of the Corporation or the other relevant entity.

COMPARISON OF THREE-YEAR CUMULATIVE TOTAL SHAREHOLDER RETURN(1)

[THIS GRAPH COMPARES THE CUMULATIVE TOTAL RETURN ON PG&E CORPORATION COMMON STOCK (EQUAL TO DIVIDENDS PLUS STOCK PRICE APPRECIATION) DURING THE PAST THREE FISCAL YEARS, SINCE PG&E CORPORATION WAS FORMED, WITH THAT OF THE STANDARD & POOR'S 500 STOCK INDEX AND THE DOW JONES UTILITIES INDEX.]

EDGAR REPRESENTATION OF DATA POINTS USED IN PRINTED GRAPHIC
COMPARISON OF THREE - YEAR CUMULATIVE TOTAL RETURNS

	PG&E CORPORATION	DOW JONES UTILITIES INDEX	S&P 500 INDEX
1996	$100	$100	$100
1997	$151	$123	$133
1998	$163	$146	$171
1999	$111	$138	$208

(1) Assumes $100 invested on December 31, 1996, in Pacific Gas and Electric Company common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns. PG&E Corporation was formed on January 1, 1997, and, on that date, all outstanding shares of Pacific Gas and Electric Company common stock were converted on a one-for-one basis to shares of PG&E Corporation common stock.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL SHAREHOLDER RETURN(1)

[THIS GRAPH COMPARES THE CUMULATIVE TOTAL RETURN ON PG&E CORPORATION COMMON STOCK (EQUAL TO DIVIDENDS PLUS STOCK PRICE APPRECIATION) DURING THE PAST FIVE FISCAL YEARS WITH THAT OF THE STANDARD & POOR'S 500 STOCK INDEX AND THE DOW JONES UTILITIES INDEX.]

EDGAR REPRESENTATION OF DATA POINTS USED IN PRINTED GRAPHIC
PG&E CORPORATION
COMPARISON OF FIVE - YEAR CUMULATIVE TOTAL RETURNS

	PG&E CORPORATION	DOW JONES UTILITIES INDEX (DJUI)	S&P 500 INDEX
1994	$100	$100	$100
1995	$125	$132	$138
1996	$100	$144	$169
1997	$151	$178	$226
1998	$163	$211	$290
1999	$111	$199	$351

(1) Assumes $100 invested on December 31, 1994, in Pacific Gas and Electric Company common stock, the Standard & Poor's 500 Stock Index, and the Dow Jones Utilities Index, and assumes quarterly reinvestment of dividends. The total shareholder returns shown are not necessarily indicative of future returns. PG&E Corporation was formed on January 1, 1997, and, on that date, all outstanding shares of Pacific Gas and Electric Company common stock were converted on a one-for-one basis to shares of PG&E Corporation common stock.

PRINCIPAL SHAREHOLDERS

The following table presents certain information regarding shareholders who are known to PG&E Corporation or Pacific Gas and Electric Company to be the beneficial owners of more than 5 percent of any class of voting securities of PG&E Corporation or Pacific Gas and Electric Company as of January 31, 2000:

CLASS OF STOCK	NAME AND ADDRESS OF BENEFICIAL OWNER	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Pacific Gas and Electric Company common stock	PG&E Corporation(1) One Market, Spear Tower, Suite 2400 San Francisco, CA 94105	326,926,667	100.00%
PG&E Corporation common stock	State Street Bank and Trust Company(2) 225 Franklin Street Boston, MA 02110	27,736,370	7.68%
PG&E Corporation common stock	Sanford C. Bernstein & Co., Inc.(3) 767 Fifth Avenue New York, NY 10153	18,300,743	5.07%

(1) As a result of the formation of the holding company on January 1, 1997, PG&E Corporation became the holder of all issued and outstanding shares of Pacific Gas and Electric Company common stock. As of January 31, 2000, PG&E Corporation and a subsidiary hold 100% of the issued and outstanding shares of Pacific Gas and Electric Company common stock.

(2) The information relating to State Street Bank and Trust Company is based on beneficial ownership as of December 31, 1999, as reported in a Schedule 13G, dated February 9, 2000, filed with the Securities and Exchange Commission. The bank holds 21,184,854 shares in its capacity as Trustee of the Pacific Gas and Electric Company Saving Fund Plan. The Trustee may not vote these shares in the absence of voting instructions from the Plan participants. The bank also holds 6,551,516 shares of PG&E Corporation common stock in various other fiduciary capacities. The bank has sole voting power with respect to 5,977,799 of these shares, shared voting power with respect to 12,747 of these shares, sole investment power with respect to 6,534,151 of these shares, and shared investment power with respect to 17,365 of these shares.

(3) The information relating to Sanford C. Bernstein & Co., Inc. is based on beneficial ownership as of December 31, 1999, as reported in a Schedule 13G, dated February 9, 2000, filed with the Securities and Exchange Commission. Sanford C. Bernstein & Co. Inc. has sole voting power with respect to 10,028,234 of these shares, shared voting power with respect to 1,614,133 of these shares, and sole investment power with respect to all 18,300,743 of these shares.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

In accordance with Section 16(a) of the Securities Exchange Act of 1934 and Securities and Exchange Commission regulations, PG&E Corporation's and Pacific Gas and Electric Company's respective directors, certain officers, and persons who own greater than 10 percent of PG&E Corporation's or Pacific Gas and Electric Company's equity securities are required to file reports of ownership and changes in ownership of such equity securities with the Securities and Exchange Commission and the principal national securities exchange on which such equity securities are registered, and to furnish PG&E Corporation or Pacific Gas and Electric Company (as the case may be) with copies of all such reports they file.

Based solely on its review of copies of such reports received or written representations from certain reporting persons, PG&E Corporation and Pacific Gas and Electric Company believe that during 1999 all filing requirements applicable to their directors, officers, and 10 percent shareholders were satisfied, except as follows: a late Form 4 was filed for Thomas B. King regarding a purchase of shares in October 1999.

VOTING ON THE INTERNET OR BY TELEPHONE

For your convenience, you may have the option of executing and submitting your proxy and voting instructions over the Internet or by telephone. The Internet and telephone voting procedures which have been made available by PG&E Corporation and Pacific Gas and Electric Company are designed to authenticate shareholders' identities, to allow shareholders to submit their proxies and voting instructions, and to confirm that shareholders' instructions have been recorded properly. Your proxy and voting instructions will be recorded as if you submitted your proxy and voting instructions by mail. PG&E Corporation and Pacific Gas and Electric Company have been advised by counsel that these Internet and telephone voting procedures are consistent with the requirements of California law.

Please note that there are separate Internet and telephone voting arrangements depending upon whether (1) your shares are registered in your name directly with PG&E Corporation and/or Pacific Gas and Electric Company (including shares held by participants in the PG&E Corporation Dividend Reinvestment Plan), or you are a participant who holds PG&E Corporation stock in any of the defined contribution retirement plans maintained by PG&E Corporation or any of its subsidiaries, or (2) your shares are held in an account at a brokerage firm or bank.

FOR SHARES REGISTERED IN THE NAME OF A SHAREHOLDER DIRECTLY WITH PG&E CORPORATION AND/OR PACIFIC GAS AND ELECTRIC COMPANY (INCLUDING SHARES HELD IN THE PG&E CORPORATION DIVIDEND REINVESTMENT PLAN), AND FOR PARTICIPANTS WHO HOLD PG&E CORPORATION STOCK IN ANY OF THE DEFINED CONTRIBUTION RETIREMENT PLANS MAINTAINED BY PG&E CORPORATION OR ANY OF ITS SUBSIDIARIES:

Holders of such shares may submit their proxies and voting instructions anytime, 24 hours a day, 7 days a week, over the Internet at the following address on the World Wide Web:

http://www.eproxy.com/pcg/

or by using a touch-tone telephone and calling the following toll-free number from anywhere in the United States or Canada:

1-800-435-6710

FOR SHARES HELD IN AN ACCOUNT AT A BROKERAGE FIRM OR BANK:

A number of brokerage firms and banks are participating in a program provided through ADP Investor Communication Services that offers Internet and telephone voting options. (This program is different from the program described above for shares registered in the name of a shareholder directly with PG&E Corporation and/or Pacific Gas and Electric Company or for participants who hold PG&E Corporation stock in any of the defined contribution retirement plans maintained by PG&E Corporation or any of its subsidiaries.) For shares held in an account at a participating brokerage firm or bank, shareholders may submit their voting instructions anytime, 24 hours a day, 7 days a week, over the Internet at the following address on the World Wide Web:

http://www.proxyvote.com

or by using a touch-tone telephone and calling, from anywhere in the United States, the toll-free telephone number shown on the voting instruction form.

Shareholders submitting proxies and voting instructions over the Internet should understand that there may be costs associated with electronic access, such as usage charges from Internet access providers and telephone companies, that must be borne by the shareholder. There are no charges to shareholders who use the telephone voting procedures.

Proxies submitted over the Internet or by telephone must be received by 4:00 p.m., Eastern time, on Tuesday, April 18, 2000. Participants who hold PG&E Corporation stock in any of the defined contribution retirement plans maintained by PG&E Corporation or any of its subsidiaries, and other beneficial owners should consult their voting instruction forms for relevant Internet and telephone voting deadlines. SHAREHOLDERS SUBMITTING PROXIES AND VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE SHOULD NOT MAIL THE PROXY VOTING INSTRUCTION FORM.

PG&E Corporation's and Pacific Gas and Electric Company's joint 1999 annual report to shareholders, including financial statements, accompanies this Joint Proxy Statement.

METHOD AND COST OF SOLICITING PROXIES

PG&E Corporation and Pacific Gas and Electric Company intend to solicit proxies principally by mail. Proxies also may be solicited by personal contact, telephone, or other means by officers and other employees of PG&E Corporation or Pacific Gas and Electric Company. PG&E Corporation and Pacific Gas and Electric Company have retained D. F. King & Co., Inc. to assist in the solicitation of proxies at an estimated fee of $11,500 plus reimbursement of reasonable expenses. In addition, brokers, banks, and other fiduciaries and nominees will be reimbursed for the reasonable expenses of forwarding the Joint Proxy Statement and other proxy materials to beneficial owners of PG&E Corporation and Pacific Gas and Electric Company stock. The entire cost of soliciting proxies will be paid by PG&E Corporation and Pacific Gas and Electric Company.

PG&E Corporation and Pacific Gas and Electric Company also have retained ChaseMellon Shareholder Services, L.L.C., to act as the independent tabulator of proxies and as the independent inspector of election at the annual meetings.

PROPOSALS BY SHAREHOLDERS - 2001

Any proposal by a shareholder to be submitted for possible inclusion in proxy soliciting materials for the annual meetings of shareholders of PG&E Corporation and Pacific Gas and Electric Company (as may be applicable depending on whether the matter relates to PG&E Corporation or Pacific Gas and Electric Company, or both) to be held in 2001 must be received by the Vice President and Corporate Secretary after April 19, 2000, but no later than November 13, 2000.

The Corporation's Bylaws provide that any shareholder wishing to make a nomination for director or wishing to introduce any business at the annual meeting of shareholders to be held in 2001 must provide timely and proper written notice of the matter, in the manner described in the Bylaws. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation no later than January 27, 2001. However, if the 2001 annual meeting is scheduled for a date that differs by more than 30 days from the anniversary date of the 2000 annual meeting, the shareholder's notice must be received no later than the tenth day following the date on which the Corporation publicly discloses the date of the 2001 annual meeting. In most circumstances, the holders of proxies solicited by the PG&E Corporation Board of Directors will have discretionary authority to vote on shareholder proposals and shareholder nominations that have been timely submitted to the Corporation, provided that the Corporation describes the matter in its proxy statement and states how the Corporation intends to vote on such matters. Shareholder proposals and shareholder nominations received after the deadline will not be considered at the annual meeting. Shareholders may obtain a copy of the Bylaws discussed above from the Corporation's reports filed with the Securities and Exchange Commission (SEC) which are available through the Corporation's web site at www.pgecorp.com or by writing to PG&E Corporation's Office of the Corporate Secretary.

The Bylaws of Pacific Gas and Electric Company do not contain any requirement for shareholders to provide advance notice of proposals or nominations they intend to present at the annual meeting. In most circumstances, the holders of proxies solicited by the Board of Directors of Pacific Gas and Electric Company will have discretionary authority to vote on shareholder proposals and nominations that have been timely submitted to the company, provided that the company describes the matters in its proxy statement and states how the company intends to vote on such matters. To be timely submitted, shareholder proposals and nominations must be provided to the Vice President and Corporate Secretary of Pacific Gas and Electric Company no later than January 27, 2001. However, if the date of the 2001 annual meeting is changed more than 30 days from the anniversary date of the 2000 annual meeting, a shareholder matter will be timely submitted if Pacific Gas and Electric Company receives notice of the matter a reasonable time before the company mails its 2001 proxy materials. For shareholder proposals and nominations submitted after the deadline, the proxyholders will have discretionary voting authority with respect to such matters to the extent permitted by applicable SEC rules.

OTHER MATTERS

Management does not know of any matter to be acted upon at the meetings other than the matters described above. However, if any other matter should properly come before the annual meetings, the proxyholders named in the enclosed proxy will vote the shares for which they hold proxies at their discretion.

By Order of the Boards of Directors of
PG&E Corporation and Pacific Gas and
Electric Company,

/s/ Leslie H. Everett

Leslie H. Everett
Vice President and Corporate Secretary,
PG&E Corporation
and Pacific Gas and Electric Company

YOUR VOTE IS IMPORTANT.
IF YOU ARE NOT EXECUTING AND SUBMITTING YOUR PROXY AND VOTING INSTRUCTIONS OVER THE INTERNET OR
BY TELEPHONE, PLEASE MARK, SIGN, DATE, AND MAIL THE ENCLOSED PROXY FORM AS SOON AS POSSIBLE.

AT THE ANNUAL MEETINGS OF SHAREHOLDERS, REAL-TIME CAPTIONING SERVICES AND ASSISTIVE LISTENING DEVICES WILL BE AVAILABLE FOR THE HEARING IMPAIRED. PLEASE CONTACT AN USHER AT THE MEETING IF YOU WISH TO BE SEATED IN THE REAL- TIME CAPTIONING SECTION OR ASK A REPRESENTATIVE AT THE SHAREHOLDER REGISTRATION DESK TO USE AN ASSISTIVE LISTENING DEVICE.

FOR SHAREHOLDERS WITH IMPAIRED VISION, AUDIO CASSETTE RECORDINGS OF THE MEETINGS WILL BE AVAILABLE WITHOUT CHARGE. PLEASE CONTACT THE OFFICE OF THE VICE PRESIDENT AND CORPORATE SECRETARY, ONE MARKET, SPEAR TOWER, SUITE 2400, SAN FRANCISCO, CA 94105 OR CALL (415) 267-7070.

APPENDIX A
RESTATED ARTICLES OF INCORPORATION
OF PG&E CORPORATION
ARTICLE EIGHTH

EIGHTH:

I. The affirmative vote of the holders of not less than a majority of the outstanding shares of "Voting Stock" (as hereinafter defined) shall be required to implement or effect any "Business Combination" (as hereinafter defined) involving the Corporation or any "Subsidiary" (as hereinafter defined) of the Corporation and any "Related Person" (as hereinafter defined), or any "Affiliate" or "Associate" (as hereinafter defined) of a Related Person, notwithstanding the fact that no vote may be required or that a lesser percentage may be specified by law, in any agreement with any national securities exchange or otherwise. In addition, the provisions of either subparagraph (1) or (2) must be satisfied:

(1) The Business Combination shall have been approved by the Board of Directors without counting the vote of any director who is not a "Disinterested Director" (as hereinafter defined); or

(2) All of the following conditions are met:

(i) The cash or "Fair Market Value" (as hereinafter defined) as of the date of the consummation of the Business Combination (the "Combination Date") of the property, securities or other consideration to be received per share by holders of a particular class or series of capital stock, as the case may be, of the Corporation in the Business Combination is not less than the highest of:

(a) the highest per share price (including brokerage commissions, transfer taxes and soliciting dealers' fees) paid by or on behalf of the Related Person in acquiring beneficial ownership of any of its holdings of such class or series of capital stock of the Corporation (A) within the two-year period immediately prior to the first public announcement of the proposed Business Combination (the "Announcement Date") or (B) in the transaction or series of transactions in which the Related Person became a Related Person, whichever is higher; or

(b) the highest Fair Market Value per share of the shares of capital stock being acquired in the Business Combination as of any date within the one-year period preceding: (A) the Announcement Date or (B) the date on which the Related Person became a Related Person, whichever is higher; or

(c) in the case of Common Stock, the highest per share book value of the Common Stock as reported at the end of the three fiscal quarters which preceded the Announcement Date, and in the case of Preferred Stock the highest preferential amount per share to which the holders of shares of such class or series of Preferred Stock would be entitled as of the Combination Date in the event of any voluntary or involuntary liquidation, dissolution or winding up of the affairs of the Corporation, regardless of whether the Business Combination to be consummated constitutes such an event.

The provisions of this paragraph I(2)(i) shall be required to be met with respect to every class or series of outstanding capital stock, whether or not the Related Person has previously acquired any shares of a particular class or series of capital stock. In all of the above instances, appropriate adjustments shall be made for recapitalizations and for stock dividends, stock splits and like distributions; and

(ii) The consideration to be received by holders of a particular class or series of capital stock shall be in cash or in the same form as previously has been paid by or on behalf of the Related Person in connection with its direct or indirect acquisition of beneficial ownership of shares of such class or series of stock. If the consideration so paid for any such shares varied as to form, the form of consideration for such shares shall be either cash or the form used to acquire beneficial ownership of the largest number of shares of such class or series of capital stock previously acquired by the Related Person; and

(iii) After such Related Person has become a Related Person and prior to the consummation of such Business Combination: (a) except as approved by the Board of Directors without counting the vote of any director who is not a Disinterested Director, there shall have been no failure to declare and pay at the regular date therefor any full quarterly dividends (whether or not cumulative) on the outstanding Preferred Stock;

(b) there shall have been (A) no reduction in the annual rate of dividends paid on the Common Stock (except as necessary to reflect any subdivision of the Common Stock) except as approved by the Board of Directors without counting the vote of any director who is not a Disinterested Director, and (B) an increase in such annual rate of dividends as necessary to reflect any reclassification (including any reverse stock split), recapitalization, reorganization or any similar transaction which has the effect of reducing the number of outstanding shares of the Common Stock, unless the failure so to increase such annual rate is approved by the Board of Directors without counting the vote of any director who is not a Disinterested Director; and (c) such Related Person shall not have become the beneficial owner of any additional shares of Voting Stock except as part of the transaction which results in such Related Person becoming a Related Person; and

(iv) After such Related Person has become a Related Person, the Related Person shall not have received the benefit, directly or indirectly (except proportionately as a shareholder), of any loans, advances, guarantees, pledges or other financial assistance or any tax credits or other tax advantages provided by the Corporation, whether in anticipation of or in connection with such Business Combination or otherwise; and

(v) A proxy or information statement describing the proposed Business Combination and complying with the requirements of the Securities Exchange Act of 1934 and the rules and regulations thereunder (or any provisions subsequently replacing such Act, rules or regulations) shall be mailed to public shareholders of the Corporation at least 30 days prior to the consummation of such Business Combination (whether or not such proxy or information statement is required to be mailed pursuant to such Act or subsequent provisions).

II. For purpose of this Article EIGHTH:

(1) The term "Business Combination" shall mean any (i) merger or consolidation of the Corporation or a Subsidiary with a Related Person or any other person which is or after such merger or consolidation would be an Affiliate or Associate of a Related Person; (ii) sale, lease, exchange, mortgage, pledge, transfer or other disposition or guarantee (in one transaction or a series of transactions) to or with or for the benefit of any Related Person or any Affiliate or Associate of any Related Person, of any assets of the Corporation or of a Subsidiary having an aggregate Fair Market Value of $100 million or more; (iii) sale, lease, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions), to the Corporation or a Subsidiary of any assets of a Related Person or any Affiliate or Associate of any Related Person having an aggregate Fair Market Value of $100 million or more; (iv) issuance, pledge or transfer of securities of the Corporation or a Subsidiary (in one transaction or a series of transactions) to or with a Related Person or any Affiliate or Associate of any Related Person in exchange for cash, securities or other property (or a combination thereof) having an aggregate Fair Market Value of $100 million or more;
(v) reclassification of securities (including any reverse stock split) or recapitalization of the Corporation, or any merger or consolidation of the Corporation with any of its Subsidiaries or any other transaction that would have the effect, either directly or indirectly, of increasing the voting power or the proportionate share of any class of equity or convertible securities of the Corporation or any Subsidiary which is directly or indirectly beneficially owned by any Related Person or any Affiliate or Associate of any Related Person; and (vi) any merger or consolidation of the Corporation with any of its Subsidiaries after which the provisions of this Article EIGHTH of the Articles of Incorporation shall not be contained in the Articles of Incorporation of the surviving entity.

(2) The term "person" shall mean any individual, firm, corporation or other entity and shall include any group comprised of any person and any other person with whom such person or any Affiliate or Associate of such person has any agreement, arrangement or understanding, directly or indirectly, for the purpose of acquiring, holding, voting or disposing of Voting Stock of the Corporation.

(3) The term "Related Person" shall mean any person (other than the Corporation, or any Subsidiary and other than any dividend reinvestment plan or profit-sharing, employee stock ownership or other employee benefit or savings plan of the Corporation or any Subsidiary or any trustee of or fiduciary with respect to any such plan when acting in such capacity) who or which:

(i) is the beneficial owner (as hereinafter defined) of five percent (5%) or more of the Voting Stock;

(ii) is an Affiliate or Associate of the Corporation and at any time within the two-year period immediately prior to the date in question was the beneficial owner of five percent (5%) or more of the then outstanding Voting Stock; or

(iii) is an assignee of or has otherwise succeeded to the beneficial ownership of any shares of Voting Stock which were at any time within the two-year period immediately prior to such time beneficially owned by any Related Person, if such assignment or succession shall have occurred in the course of a transaction or series of transactions not involving a public offering within the meaning of the Securities Act of 1933.

(4) A person shall be a "beneficial owner" of any Voting Stock:

(i) which such person or any of its Affiliates or Associates beneficially owns, directly or indirectly;

(ii) which such person or any of its Affiliates or Associates has, directly or indirectly, (a) the right to acquire (whether such right is exercisable immediately or only after the passage of time), pursuant to any agreement, arrangement or understanding or upon the exercise of conversion rights, exchange rights, warrants or options, or otherwise, or (b) the right to vote pursuant to any agreement, arrangement or understanding; or

(iii) which is beneficially owned, directly or indirectly, by any other person with which such person or any of its Affiliates or Associates has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting or disposing of any shares of Voting Stock.

(5) For the purposes of determining whether a person is a Related Person pursuant to subparagraph (3) of this paragraph II, the number of shares of Voting Stock deemed to be outstanding shall include shares deemed owned through application of subparagraph (4) of this paragraph II but shall not include any other shares of Voting Stock which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, warrants or options, or otherwise.

(6) The term "Affiliate," used to indicate a relationship with a specified person, shall mean a person that directly, or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such specified person. The term "Associate," used to indicate a relationship with a specified person, shall mean (i) any person (other than the Corporation or a Subsidiary) of which such specified person is an officer or partner or is, directly or indirectly, the beneficial owner of 10% or more of any class of equity securities, (ii) any trust or other estate in which such specified person has a substantial beneficial interest or as to which such specified person serves as trustee or in a similar fiduciary capacity, (iii) any relative or spouse of such specified person or any relative of such spouse, who has the same home as such specified person or who is a director or officer of the Corporation or any Subsidiary, and (iv) any person who is a director or officer of such specified person or any of its parents or subsidiaries (other than the Corporation or a Subsidiary).

(7) The term "Subsidiary" means any corporation or other entity of which a majority of any class of equity securities is owned, directly or indirectly, by the Corporation; provided, however, that for the purposes of the definition of Related Person set forth in subparagraph (3) of this paragraph II, the term "Subsidiary" shall mean only a corporation of which a majority of the outstanding shares of capital stock of such corporation entitled to vote generally in the election of directors is owned, directly or indirectly, by the Corporation or, in the case of other entities, the Corporation has the direct or indirect contractual power to designate a majority of the individuals or representatives exercising functions similar to those exercised by directors of a corporation, or the Corporation has the power to approve a transaction which would otherwise be a Business Combination involving such entity.

(8) The term "Disinterested Director" means any member of the Board of Directors, while such person is a member of the Board of Directors, who is not an Affiliate, Associate or a representative of the Related Person involved in a proposed Business Combination and was a member of the Board of Directors immediately prior to the time that the Related Person became a Related Person, and any successor of a Disinterested Director, while such successor is a member of the Board of Directors, who is not an Affiliate, Associate or a representative of the Related Person and is recommended or elected to succeed a Disinterested Director by the Board of Directors without counting the vote of any director who is not a Disinterested Director.

(9) For the purposes of paragraph I(2)(i) of this Article EIGHTH, the term "other consideration to be received" shall include, without limitation, capital stock retained by the shareholders.

(10) The term "Voting Stock" shall mean all of the outstanding shares of capital stock of the Corporation entitled to vote generally in the election of directors, and each reference to a proportion of shares of Voting Stock shall refer to such proportion of the votes entitled to be cast by such shares voting together as one class.

(11) The term "Fair Market Value" means: (i) in case of capital stock, the highest closing sale price during the 30-day period immediately preceding the date in question of a share of such stock on the Composite Tape for the New York Stock Exchange Listed Stocks, or, if such stock is not quoted on the Composite Tape, on the New York Stock Exchange, or if such stock is not listed on such Exchange, on the principal United States securities exchange registered under the Securities Exchange Act of 1934 on which such stock is listed, or, if such stock is not listed on any such stock exchange, the highest closing bid quotation with respect to a share of such stock during the 30-day period preceding the date in question on the National Association of Securities Dealers, Inc. Automated Quotations System or any successor system then in use, or if no such quotations are available, the fair market value on the

date in question of a share of such stock as determined in good faith by the Board of Directors without counting the vote of any director who is not a Disinterested Director; and (ii) in the case of property other than cash or stock, the fair market value of such property on the date in question as determined in good faith by the Board of Directors without counting the vote of any director who is not a Disinterested Director.

(12) A Related Person shall be deemed to have acquired a share of Voting Stock at the time when such Related Person became the beneficial owner thereof. If the Board of Directors without counting the vote of any director who is not a Disinterested Director is not able to determine the price at which a Related Person has acquired a share of Voting Stock, such price shall be deemed to be the Fair Market Value of the shares in question at the time when the Related Person becomes the beneficial owner thereof. With respect to shares owned by Affiliates or other persons whose ownership is attributed to a Related Person under the foregoing definition of Related Person, the price deemed to be paid therefor by such Related Person shall be the price paid upon the acquisition thereof by such Affiliate, Associate or other person, or, if such price is not determinable by the Board of Directors without counting the vote of any director who is not a Disinterested Director, the Fair Market Value of the shares in question at the time when the Affiliate, Associate, or other such person became the beneficial owner thereof.

III. The fact that any Business Combination complies with the provisions of paragraph I(2) of this Article EIGHTH shall not be construed to impose any fiduciary duty, obligation or responsibility on the Board of Directors, or any member thereof, to approve such Business Combination or recommend its adoption or approval to the shareholders of the Corporation, nor shall such compliance limit, prohibit or otherwise restrict in any manner the Board of Directors, or any member thereof, with respect to evaluations of or actions and responses taken with respect to such Business Combination.

IV. The Board of Directors of the Corporation shall have the power and duty to determine for the purposes of this Article EIGHTH, on the basis of information known to them after reasonable inquiry and in accordance with the terms of this Article EIGHTH, whether a person is a Related Person and whether a director is a Disinterested Director. Once the Board of Directors has made a determination pursuant to the preceding sentence that a person is a Related Person, the Board of Directors of the Corporation, without counting the vote of any director who is not a Disinterested Director with respect to such Related Person, shall have the power and duty to interpret all of the terms and provisions of this Article EIGHTH and to determine on the basis of the information known to them after reasonable inquiry all facts necessary to ascertain compliance with this Article EIGHTH including, without limitation, (1) the number of shares of Voting Stock beneficially owned by any person, (2) whether a person is an Affiliate or Associate of another, (3) whether the assets which are the subject of any Business Combination have, or the consideration to be received for the issuance or transfer of securities by the Corporation or any Subsidiary of the Corporation in any Business Combination has, an aggregate Fair Market Value of $100 million or more, and (4) whether all of the applicable conditions set forth in paragraph I(2) of this Article EIGHTH have been met with respect to any Business Combination. Any determination pursuant to this Article EIGHTH made in good faith shall be binding and conclusive on all parties.

V. The directors of the Corporation, when evaluating any proposal or offer which would involve a Business Combination or the merger or consolidation of the Corporation or any of its Subsidiaries with another corporation, the sale of all or substantially all of the assets of the Corporation or any of its Subsidiaries, a tender offer or exchange offer for any capital stock of the Corporation or any of its Subsidiaries or any similar transaction shall give due consideration to all factors they may consider relevant. Such factors may include, without limitation, (a) the adequacy, both in amount and form, of the consideration offered in relation not only to the current market price of the Corporation's outstanding securities, but also the current value of the Corporation in a freely negotiated transaction with other potential acquirers and the Board's estimate of the Corporation's future value (including the unrealized value of its properties, assets and prospects) as an independent going concern, (b) the financial and managerial resources and future prospects of the acquirer, and (c) the legal, economic, environmental, regulatory and social effects of the proposed transaction on the Corporation's and its Subsidiaries' employees, customers, suppliers and other affected persons and entities and on the communities and geographic areas in which the Corporation and its Subsidiaries provide utility service or are located, and in particular, the effect on the Corporation's and its Subsidiaries' ability to safely and reliably meet any public utility obligations at reasonable rates.

VI. Nothing herein shall be construed to relieve any Related Person from any fiduciary obligation imposed by law.

[RECYCLED PAPER LOGO] Printed with soybean ink on recycled/recyclable paper.

[LOGO] PG&E CORPORATION-TM-

YOUR PROXY IS SOLICITED BY THE PG&E CORPORATION BOARD OF DIRECTORS. UNLESS CONTRARY INSTRUCTIONS ARE GIVEN ON THE REVERSE SIDE OF THIS PROXY CARD, THE DESIGNATED PROXIES WILL VOTE THE PG&E CORPORATION SHARES FOR WHICH THEY HOLD PROXIES FOR ITEMS 1, 2, 3, AND 4 AND AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

The undersigned hereby appoints Robert D. Glynn, Jr. and Leslie H. Everett, or either of them, proxies of the undersigned, with full power of substitution, to vote the stock of the undersigned at the annual meeting of shareholders of PG&E Corporation, to be held at 200 Boylston Street, Boston, Massachusetts, on Wednesday, April 19, 2000, at 10:00 a.m., and at any adjournment or postponement thereof, as indicated on this proxy card and upon all motions and resolutions which may properly be presented for consideration at said meeting.

(CONTINUED, AND TO BE MARKED, DATED, AND SIGNED ON THE REVERSE SIDE.)

YOUR PROXY IS SOLICITED BY THE PG&E CORPORATION BOARD OF DIRECTORS. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE FOR ITEMS 1, 2, 3, AND 4. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE AGAINST ITEMS 5, 6, 7, 8, 9 AND 10.

Please mark your votes as /X/ indicated in this example

	FOR ALL	WITHHOLD FOR ALL
ITEM 1. ELECTION OF DIRECTORS	/ /	/ /

NOMINEES ARE:

01-Richard A. Clarke, 02-Harry M. Conger, 03-David A. Coulter, 04-C. Lee Cox, 05-William S. Davila, 06-Robert D. Glynn, Jr., 07-David M. Lawrence, MD, 08-Mary S. Metz, 09-Carl E. Reichardt, 10-John C. Sawhill, 11-Barry Lawson Williams

WITHHOLD vote only for:

		FOR	AGAINST	ABSTAIN
ITEM 2.	RATIFICATION OF APPOINTMENT OF INDEPENDENT PUBLIC ACCOUNTANTS	/ /	/ /	/ /
ITEM 3.	PROPOSAL TO ELIMINATE "SUPERMAJORITY VOTE" PROVISION	/ /	/ /	/ /
ITEM 4.	PROPOSAL TO REDUCE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS	/ /	/ /	/ /
ITEM 5.	SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS	/ /	/ /	/ /
ITEM 6.	SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING	/ /	/ /	/ /
ITEM 7.	SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY	/ /	/ /	/ /
ITEM 8.	SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING	/ /	/ /	/ /
ITEM 9.	SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK	/ /	/ /	/ /
ITEM 10.	SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS	/ /	/ /	/ /

SPECIAL ACTION

Mark here to discontinue duplicate Annual Report mailing for this account (for multiple-account holders only). / /

I/we plan to attend the annual meeting in Boston, Massachusetts. / /

SIGNATURE --------------------- SIGNATURE --------------------- DATE ----------

IF YOU ARE SIGNING FOR THE SHAREHOLDER, PLEASE SIGN THE SHAREHOLDER'S NAME AND YOUR NAME, AND SPECIFY THE CAPACITY IN WHICH YOU ACT.

[LOGO] PG&E CORPORATION-TM-

YOUR PROXY IS SOLICITED BY THE PG&E CORPORATION BOARD OF DIRECTORS. UNLESS CONTRARY INSTRUCTIONS ARE GIVEN ON THE REVERSE SIDE OF THIS PROXY CARD, THE DESIGNATED PROXIES WILL VOTE THE PG&E CORPORATION SHARES FOR WHICH THEY HOLD PROXIES FOR ITEMS 1, 2, 3, AND 4 AND AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

The undersigned hereby appoints Robert D. Glynn, Jr. and Leslie H. Everett, or either of them, proxies of the undersigned, with full power of substitution, to vote the stock of the undersigned at the annual meeting of shareholders of PG&E Corporation, to be held at 200 Boylston Street, Boston, Massachusetts, on Wednesday, April 19, 2000, at 10:00 a.m., and at any adjournment or postponement thereof, as indicated on this proxy card and upon all motions and resolutions which may properly be presented for consideration at said meeting.

(CONTINUED, AND TO BE MARKED, DATED, AND SIGNED ON THE REVERSE SIDE.)

As an alternative to completing and mailing this proxy card, you may execute and submit your proxy and voting instructions over the Internet at HTTP://WWW.EPROXY.COM/PCG/ or by touch-tone telephone at 1-800-435-6710 (from anywhere in the United States or Canada). These Internet and telephone voting procedures comply with California law.

- IF YOU ARE NOT SUBMITTING YOUR PROXY OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS PROXY CARD IN THE ACCOMPANYING ENVELOPE. -

[LOGO] PG&E CORPORATION-TM-

ANNUAL MEETING OF SHAREHOLDERS

To be held at:

Four Seasons Hotel - Boston
200 Boylston Street
Boston, Massachusetts

April 19, 2000, at 10:00 a.m.

- PLEASE USE THE ATTACHED TICKET TO ATTEND THE PG&E CORPORATION ANNUAL MEETING, OR YOU MAY REGISTER AT THE MEETING. -

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Note: Cellular telephones, cameras, tape recorders, etc., will not be allowed in the meeting room during the annual meeting, other than for PG&E Corporation purposes. A checkroom will be provided. For your protection, all briefcases, purses, packages, etc., will be subject to inspection as you enter the meeting. We regret any inconvenience this may cause you.

Real-time captioning services and assistive listening devices will be available at the meeting for shareholders with impaired hearing. Please contact an usher at the meeting if you wish to be seated in the real-time captioning section, or request an assistive listening device from a representative at the shareholder registration desk.

YOUR PROXY IS SOLICITED BY THE PG&E CORPORATION BOARD OF DIRECTORS. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE FOR ITEMS 1, 2, 3, AND 4. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

Please mark your votes as /X/ indicated in this example

		FOR ALL	WITHHOLD FOR ALL
ITEM 1.	ELECTION OF DIRECTORS	/ /	/ /

NOMINEES ARE:

01-Richard A. Clarke, 02-Harry M. Conger, 03-David A. Coulter, 04-C. Lee Cox, 05-William S. Davila, 06-Robert D. Glynn, Jr., 07-David M. Lawrence, MD, 08-Mary S. Metz, 09-Carl E. Reichardt, 10-John C. Sawhill, 11-Barry Lawson Williams

WITHHOLD vote only for:

		FOR	AGAINST	ABSTAIN
ITEM 2.	RATIFICATION OF APPOINTMENT OF INDEPENDENT PUBLIC ACCOUNTANTS	/ /	/ /	/ /
ITEM 3.	PROPOSAL TO ELIMINATE "SUPERMAJORITY VOTE" PROVISION	/ /	/ /	/ /
ITEM 4.	PROPOSAL TO REDUCE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS	/ /	/ /	/ /
ITEM 5.	SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS	/ /	/ /	/ /
ITEM 6.	SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING	/ /	/ /	/ /
ITEM 7.	SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY	/ /	/ /	/ /
ITEM 8.	SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING	/ /	/ /	/ /
ITEM 9.	SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK	/ /	/ /	/ /
ITEM 10.	SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS	/ /	/ /	/ /

SPECIAL ACTION

Mark here to discontinue duplicate Annual Report mailing for this account (for multiple-account holders only). / /

I/we plan to attend the annual meeting in Boston, Massachusetts. / /

SIGNATURE --------------------- SIGNATURE --------------------- DATE -----------

IF YOU ARE SIGNING FOR THE SHAREHOLDER, PLEASE SIGN THE SHAREHOLDER'S

NAME AND YOUR NAME, AND SPECIFY THE CAPACITY IN WHICH YOU ACT.

- IF YOU ARE NOT SUBMITTING YOUR PROXY OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS PROXY CARD IN THE ACCOMPANYING ENVELOPE. -
(RETAIN ANNUAL MEETING TICKET BELOW.)

PRIOR TO VOTING, READ THE ACCOMPANYING JOINT PROXY STATEMENT AND THE ABOVE PROXY CARD.

VOTE ON THE INTERNET

1. Go to the website HTTP://WWW.EPROXY.COM/PCG/ anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this proxy form.

VOTE BY TELEPHONE

1. Using any touch-tone telephone in the U.S. or Canada, call the TOLL-FREE number 1-800-435-6710 - anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this proxy form.

VOTE BY MAIL

1. Mark, sign, and date the proxy card.

2. Detach the proxy card (the top portion of this page) and mail it promptly, in the accompanying POSTAGE-PAID envelope.

PROXIES AND VOTING INSTRUCTIONS SUBMITTED OVER THE INTERNET OR BY TELEPHONE MUST BE RECEIVED BY 4:00 P.M., EASTERN TIME, ON TUESDAY, APRIL 18, 2000.

[LOGO] PG&E CORPORATION-TM-

2000 ANNUAL MEETING TICKET

Ticket for the annual meeting on April 19, 2000, at 10:00 a.m. to be held at the Four Seasons Hotel - Boston, 200 Boylston Street, Boston, Massachusetts. Doors open at 9:00 a.m. You may bypass the shareholder registration area and present this ticket at the entrance to the meeting room.

(See reverse side for additional information.)

[LOGO] PG&E CORPORATION-TM-

2000 ANNUAL MEETING
PG&E CORPORATION
RETIREMENT SAVINGS PLAN
VOTING INSTRUCTIONS TO THE TRUSTEE - 2000

TO FIDELITY MANAGEMENT TRUST COMPANY, TRUSTEE:

Pursuant to the provisions of the PG&E Corporation Retirement Savings Plan, you are instructed as indicated on this voting instruction card with respect to voting the shares of stock credited to my account in the Plan as of February 22, 2000, at the annual meeting of shareholders of PG&E Corporation to be held on April 19, 2000, and at any adjournment or postponement thereof.

(CONTINUED, AND TO BE MARKED, DATED, AND SIGNED ON THE REVERSE SIDE.)

TO PARTICIPANTS IN THE RETIREMENT SAVINGS PLAN:

If you sign but do not otherwise complete the card, you will be instructing the Trustee to vote all shares in accordance with the recommendations of the PG&E Corporation Board of Directors.

- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

TO PARTICIPANTS IN THE RETIREMENT SAVINGS PLAN:

AS A PARTICIPANT, YOU ARE ENTITLED TO DIRECT THE TRUSTEE HOW TO VOTE THE SHARES OF PG&E CORPORATION COMMON STOCK ALLOCATED TO YOUR ACCOUNT. The above voting instruction card is provided for your use in giving the Trustee of the Plan confidential instructions to vote your stock held in the Plan at PG&E Corporation's annual meeting of shareholders on April 19, 2000. You have one vote for each share of PG&E Corporation common stock credited to your account as of February 22, 2000. Enclosed is a joint proxy statement which sets forth the business to be transacted at the meeting. Please mark your instructions on the above card and sign, date, and return it in the accompanying envelope. As an alternative to completing and mailing the card, you may enter your voting instructions by touch-tone telephone at 1-800-435-6710 (only available in the United States and Canada) or over the Internet at http://www.eproxy.com/pcg/. These Internet and telephone voting procedures comply with California law. Stock in your Plan account for which the Trustee has not received voting instructions will not be voted by the Trustee. Participants who also own stock outside the Plan will receive a separate proxy voting instruction card for those shares.

PG&E CORPORATION DIRECTORS RECOMMEND A VOTE FOR ITEMS 1, 2, 3, AND 4. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

Please mark your votes as /X/ indicated in this example

	FOR ALL	WITHHOLD FOR ALL
ITEM 1. ELECTION OF DIRECTORS	/ /	/ /

NOMINEES ARE:

01-Richard A. Clarke, 02-Harry M. Conger, 03-David A. Coulter, 04-C. Lee Cox, 05-William S. Davila, 06-Robert D. Glynn, Jr., 07-David M. Lawrence, MD, 08-Mary S. Metz, 09-Carl E. Reichardt, 10-John C. Sawhill, 11-Barry Lawson Williams

WITHHOLD vote only for:

		FOR	AGAINST	ABSTAIN
ITEM 2.	RATIFICATION OF APPOINTMENT OF INDEPENDENT PUBLIC ACCOUNTANTS	/ /	/ /	/ /
ITEM 3.	PROPOSAL TO ELIMINATE "SUPERMAJORITY VOTE" PROVISION	/ /	/ /	/ /
ITEM 4.	PROPOSAL TO REDUCE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS	/ /	/ /	/ /
ITEM 5.	SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS	/ /	/ /	/ /
ITEM 6.	SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING	/ /	/ /	/ /
ITEM 7.	SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY	/ /	/ /	/ /
ITEM 8.	SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING	/ /	/ /	/ /
ITEM 9.	SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK	/ /	/ /	/ /
ITEM 10.	SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS	/ /	/ /	/ /

SIGNATURE -------------------------------------- DATE -----------------------------

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- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

PRIOR TO VOTING, READ THE ACCOMPANYING JOINT PROXY STATEMENT AND THE ABOVE VOTING INSTRUCTION CARD.

VOTE ON THE INTERNET

1. Go to the website HTTP://WWW.EPROXY.COM/PCG/ anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY TELEPHONE

1. Using any touch-tone telephone in the U.S. or Canada, call the TOLL-FREE number 1-800-435-6710 - anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY MAIL

1. Mark, sign, and date the voting instruction card.

2. Detach the voting instruction card (the top portion of this page) and mail it promptly in the accompanying POSTAGE-PAID envelope.

FOR SHARES IN YOUR PLAN ACCOUNT, VOTING INSTRUCTIONS SUBMITTED OVER THE INTERNET, BY TELEPHONE, OR BY MAIL MUST BE RECEIVED BY THE TRUSTEE BY 4:00 P.M., EASTERN TIME, ON SUNDAY, APRIL 16, 2000. VOTING INSTRUCTIONS RECEIVED AFTER THAT TIME WILL NOT BE COUNTED.

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION.)

[LOGO] PG&E CORPORATION-TM-

2000 ANNUAL MEETING
PACIFIC GAS AND ELECTRIC COMPANY
SAVINGS FUND PLAN
VOTING INSTRUCTIONS TO THE TRUSTEE - 2000

TO STATE STREET BANK AND TRUST COMPANY, TRUSTEE:

Pursuant to the provisions of the Pacific Gas and Electric Company Savings Fund Plan, you are instructed as indicated on this voting instruction card with respect to voting the shares of stock credited to my account in the Plan as of February 22, 2000, at the annual meeting of shareholders of PG&E Corporation to be held on April 19, 2000, and at any adjournment or postponement thereof.

(CONTINUED, AND TO BE MARKED, DATED, AND SIGNED ON THE REVERSE SIDE.)

TO PARTICIPANTS IN THE SAVINGS FUND PLAN:

If you sign but do not otherwise complete the card, you will be instructing the Trustee to vote all shares in accordance with the recommendations of the PG&E Corporation Board of Directors.

- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

TO PARTICIPANTS IN THE SAVINGS FUND PLAN:

AS A PARTICIPANT, YOU ARE ENTITLED TO DIRECT THE TRUSTEE HOW TO VOTE THE SHARES OF PG&E CORPORATION COMMON STOCK ALLOCATED TO YOUR ACCOUNT. The above voting instruction card is provided for your use in giving the Trustee of the Plan confidential instructions to vote your stock held in the Plan at PG&E Corporation's annual meeting of shareholders on April 19, 2000. You have one vote for each share of PG&E Corporation common stock credited to your account as of February 22, 2000. Enclosed is a joint proxy statement which sets forth the business to be transacted at the meeting. Please mark your instructions on the above card and sign, date, and return it in the accompanying envelope. As an alternative to completing and mailing the card, you may enter your voting instructions by touch-tone telephone at 1-800-435-6710 (only available in the United States and Canada) or over the Internet at http://www.eproxy.com/pcg/. These Internet and telephone voting procedures comply with California law. Stock in your Plan account for which the Trustee has not received voting instructions will not be voted by the Trustee. Participants who also own stock outside the Plan will receive a separate proxy voting instruction card for those shares.

PG&E CORPORATION DIRECTORS RECOMMEND A VOTE FOR ITEMS 1, 2, 3, AND 4. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

Please mark your votes as /X/ indicated in this example

	FOR ALL	WITHHOLD FOR ALL
ITEM 1. ELECTION OF DIRECTORS	/ /	/ /

NOMINEES ARE:

01-Richard A. Clarke, 02-Harry M.Conger, 03-David A. Coulter, 04-C. Lee Cox, 05-William S. Davila, 06-Robert D. Glynn, Jr., 07-David M. Lawrence, MD, 08-Mary S. Metz, 09-Carl E. Reichardt, 10-John C. Sawhill, 11-Barry Lawson Williams

WITHHOLD vote only for:

		FOR	AGAINST	ABSTAIN
ITEM 2.	RATIFICATION OF APPOINTMENT OF INDEPENDENT PUBLIC ACCOUNTANTS	/ /	/ /	/ /
ITEM 3.	PROPOSAL TO ELIMINATE "SUPERMAJORITY VOTE" PROVISION	/ /	/ /	/ /
ITEM 4.	PROPOSAL TO REDUCE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS	/ /	/ /	/ /
ITEM 5.	SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS	/ /	/ /	/ /
ITEM 6.	SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING	/ /	/ /	/ /
ITEM 7.	SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY	/ /	/ /	/ /
ITEM 8.	SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING	/ /	/ /	/ /
ITEM 9.	SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK	/ /	/ /	/ /
ITEM 10.	SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS	/ /	/ /	/ /

SIGNATURE -- DATE --------------------

- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

PRIOR TO VOTING, READ THE ACCOMPANYING JOINT PROXY STATEMENT

AND THE ABOVE VOTING INSTRUCTION CARD.

VOTE ON THE INTERNET

1. Go to the website HTTP://WWW.EPROXY.COM/PCG/ anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY TELEPHONE

1. Using any touch-tone telephone in the U.S. or Canada, call the TOLL-FREE number 1-800-435-6710 - anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY MAIL

1. Mark, sign, and date the voting instruction card.

2. Detach the voting instruction card (the top portion of this page) and mail it promptly in the accompanying POSTAGE-PAID envelope.

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(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION.)

[LOGO] PG&E CORPORATION-TM-

2000 ANNUAL MEETING
PG&E GAS TRANSMISSION
NORTHWEST CORPORATION
SAVINGS FUND PLAN
VOTING INSTRUCTIONS TO THE TRUSTEE - 2000

TO MERRILL LYNCH TRUST COMPANY, FSB, TRUSTEE:

Pursuant to the provisions of the PG&E Gas Transmission - Northwest Corporation Savings Fund Plan, you are instructed as indicated on this voting instruction card with respect to voting the shares of stock held for my account in the Plan as of February 22, 2000, at the annual meeting of shareholders of PG&E Corporation to be held on April 19, 2000, and at any adjournment or postponement thereof.

(CONTINUED, AND TO BE MARKED, DATED, AND SIGNED ON THE REVERSE SIDE.)

TO PARTICIPANTS IN THE SAVINGS FUND PLAN:

If you sign but do not otherwise complete the card, you will be instructing the Trustee to vote all shares in accordance with the recommendations of the PG&E Corporation Board of Directors.

- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

TO PARTICIPANTS IN THE SAVINGS FUND PLAN:

AS A PARTICIPANT, YOU ARE ENTITLED TO DIRECT THE TRUSTEE HOW TO VOTE THE SHARES OF PG&E CORPORATION COMMON STOCK ALLOCATED TO YOUR ACCOUNT. The above voting instruction card is provided for your use in giving the Trustee of the Plan confidential instructions to vote your stock held in the Plan at PG&E Corporation's annual meeting of shareholders on April 19, 2000. You have one vote for each share of PG&E Corporation common stock credited to your account as of February 22, 2000. Enclosed is a joint proxy statement which sets forth the business to be transacted at the meeting. Please mark your instructions on the above card and sign, date, and return it in the accompanying envelope. As an alternative to completing and mailing the card, you may enter your voting instructions by touch-tone telephone at 1-800-435-6710 (only available in the United States and Canada) or over the Internet at http://www.eproxy.com/pcg/. These Internet and telephone voting procedures comply with California law. Stock in your Plan account for which the Trustee has not received voting instructions will not be voted by the Trustee. Participants who also own stock outside the Plan will receive a separate proxy voting instruction card for those shares.

PG&E CORPORATION DIRECTORS RECOMMEND A VOTE FOR ITEMS 1, 2, 3, AND 4. PG&E CORPORATION DIRECTORS RECOMMEND A VOTE AGAINST ITEMS 5, 6, 7, 8, 9, AND 10.

Please mark your votes as /X/ indicated in this example

	FOR ALL	WITHHOLD FOR ALL
ITEM 1. ELECTION OF DIRECTORS	/ /	/ /

NOMINEES ARE:

01-Richard A. Clarke, 02-Harry M. Conger, 03-David A. Coulter, 04-C. Lee Cox, 05-William S. Davila, 06-Robert D. Glynn, Jr., 07-David M. Lawrence, MD, 08-Mary S. Metz, 09-Carl E. Reichardt, 10-John C. Sawhill, 11-Barry Lawson Williams

WITHHOLD vote only for:

	FOR	AGAINST	ABSTAIN
ITEM 2. RATIFICATION OF APPOINTMENT OF INDEPENDENT PUBLIC ACCOUNTANTS	/ /	/ /	/ /
ITEM 3. PROPOSAL TO ELIMINATE "SUPERMAJORITY VOTE" PROVISION	/ /	/ /	/ /
ITEM 4. PROPOSAL TO REDUCE AUTHORIZED MINIMUM AND MAXIMUM NUMBER OF DIRECTORS	/ /	/ /	/ /
ITEM 5. SHAREHOLDER PROPOSAL REGARDING INDEPENDENT DIRECTORS	/ /	/ /	/ /
ITEM 6. SHAREHOLDER PROPOSAL REGARDING CONFIDENTIAL SHAREHOLDER VOTING	/ /	/ /	/ /
ITEM 7. SHAREHOLDER PROPOSAL REGARDING SHAREHOLDER DEMOCRACY	/ /	/ /	/ /
ITEM 8. SHAREHOLDER PROPOSAL REGARDING CUMULATIVE VOTING	/ /	/ /	/ /
ITEM 9. SHAREHOLDER PROPOSAL REGARDING COMPENSATION OF DIRECTORS IN STOCK	/ /	/ /	/ /
ITEM 10. SHAREHOLDER PROPOSAL REGARDING SEVERANCE BENEFITS RECEIVED DURING MERGERS OR ACQUISITIONS	/ /	/ /	/ /

SIGNATURE -- DATE -------------------

- IF YOU ARE NOT SUBMITTING YOUR VOTING INSTRUCTIONS OVER THE INTERNET OR BY TELEPHONE, PLEASE DETACH HERE AND MAIL THIS CARD IN THE ACCOMPANYING ENVELOPE. -

PRIOR TO VOTING, READ THE ACCOMPANYING JOINT PROXY STATEMENT AND THE ABOVE VOTING INSTRUCTION CARD.

VOTE ON THE INTERNET

1. Go to the website HTTP://WWW.EPROXY.COM/PCG/ anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY TELEPHONE

1. Using any touch-tone telephone in the U.S. or Canada, call the TOLL-FREE number 1-800-435-6710 - anytime, 24 HOURS A DAY, 7 DAYS A WEEK and follow the instructions.

2. When prompted, enter the 11-DIGIT CONTROL NUMBER located in the lower-right portion of this voting instruction form.

VOTE BY MAIL

1. Mark, sign, and date the voting instruction card.

2. Detach the voting instruction card (the top portion of this page) and mail it promptly in the accompanying POSTAGE-PAID envelope.

FOR SHARES IN YOUR PLAN ACCOUNT, VOTING INSTRUCTIONS SUBMITTED OVER THE INTERNET, BY TELEPHONE, OR BY MAIL MUST BE RECEIVED BY THE TRUSTEE BY 4:00 P.M., EASTERN TIME, ON SUNDAY, APRIL 16, 2000. VOTING INSTRUCTIONS RECEIVED AFTER THAT TIME WILL NOT BE COUNTED.

(SEE REVERSE SIDE FOR ADDITIONAL INFORMATION.)