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1996 Annual Report

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PG&E Corporation

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A New Beginning

[illegible] was formed on January 1, 1997. Its subsidiaries include Pacific Gas and Electric Company (PG&E), Pacific Gas Transmission (PGT) and PG&E Enterprises. Through these subsidiaries and their affiliates, PG&E Corporation markets energy services in North America and Australia. In Northern and Central California, PG&E provides natural gas and electric service to more than 13 million people. PGT and its affiliates own and operate natural gas transmission lines from the California border to Canada and in the Pacific Northwest, Texas and Queensland, Australia. U.S. Generating Company (USGen), an unregulated joint venture with Bechtel Enterprises, Inc., is a leading competitive power supplier in U.S. markets. USGen and its affiliates have ownership interests and management responsibilities in 17 power plants located in eight states with a combined generation capacity of nearly 3,400 megawatts. While PG&E Corporation's markets now are primarily in the U.S., the corporation continues to identify and evaluate energy opportunities in other nations around the world.

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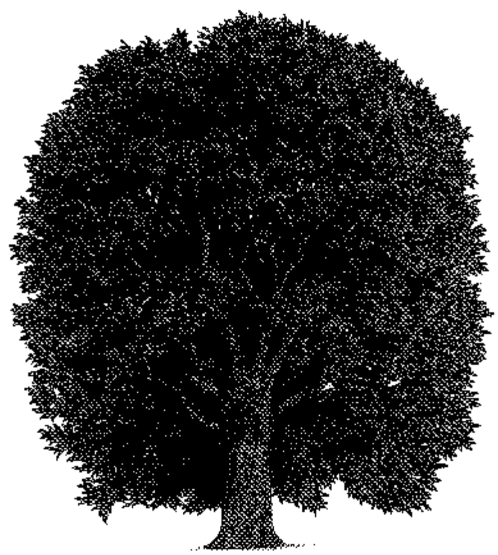
(dollars in thousands, except per share amounts)	1996	1995	% Change
For the Year			
Operating revenues	$ 9,609,972	$ 9,621,765	(0.1)
Operating income	$ 1,895,585	$ 2,762,985	(31.4)
Net income	$ 755,209	$ 1,338,885	(43.6)
Earnings available for common stock	$ 722,096	$ 1,268,597	(43.1)
Earnings per common share	$ 1.75	$ 2.99	(41.5)
Dividends declared per common share	$ 1.77	$ 1.96	(9.7)
Capital expenditures (including AFUDC)	$ 1,403,769	$ 964,657	45.5
Total electric sales to customers (kWh — in thousands)	74,394,282	75,358,632	(1.3)
Total gas sales to customers (Mcf — in thousands)	264,439	269,904	(2.0)
At Year End			
Total assets	$ 26,129,925	$ 26,850,290	(2.7)
Total electric customers	4,463,000	4,408,000	1.2
Total gas customers	3,677,000	3,628,000	1.4
Number of common shareholders	198,000	220,000	(10.0)
Number of common shares outstanding	403,504,292	414,025,586	(2.5)
Number of employees	22,000	22,000	–



The strength of a living thing
can be recognized in its endurance...

Welcome to the first annual report of PG&E Corporation, the holding company which our shareholders approved at the annual meeting last April. PG&E Corporation was officially created on January 1, 1997.

Under the new structure, Pacific Gas and Electric Company (PG&E), Pacific Gas Transmission (PGT) and PG&E Enterprises are now subsidiaries of PG&E Corporation.

But the holding company is more than just a new name and redefined corporate structure. It is a new beginning.

We are confident that it will significantly increase our flexibility, will add to our ability to respond to competitive changes in the utility industry and to new opportunities in energy services businesses, and will help us to meet our goal as we approach the millennium: to be a recognized leader in the energy industry, here in the U.S. and around the globe.

The name of the holding company is, of course, familiar. It reflects the experience, strength and success of Pacific Gas and Electric Company, which has provided energy to millions of customers in Northern and Central California for almost a century.

But while its heritage is rooted in the past, PG&E Corporation is focused squarely on the ample opportunities for profitable growth it sees in the future.

A new day has dawned in the energy industry, bringing with it new complexities and new opportunities in domestic and foreign markets.

In the competitive and dynamic business environment now emerging, successful companies will be those with the skills, resources and agility to keep up with change, recognize new possibilities, market the range of energy services customers want and do it all profitably.

That is the kind of organization we are building with PG&E Corporation.

We know what PG&E Corporation must do, to achieve its objectives. We also know that in the short run it won't always be an easy task.

Over the next five years, a significant portion of our business will be transformed from a monopoly to a competitive enterprise. The various component parts of the business that traditionally have been bundled together in vertically integrated utilities now will be unbundled — to give customers choice in the services they receive.

Some components, such as distribution, will remain regulated. Others, such as electric generation, will be largely deregulated and fully competitive.

To help customers manage their needs in this new marketplace, an energy services industry is now developing and will continue to expand and prosper. PG&E Corporation intends to be an active participant in all elements of this new gas and electric services business.

During the transition to a restructured energy marketplace, as we continue to take the steps needed to make components of our business more competitive, earnings will be lower than in the recent past.

In particular, we will accelerate the depreciation of our Diablo Canyon nuclear power plant between now and the end of 2001 in order to price the electricity it generates at competitive levels. This means revenues will be offset by greater depreciation, lowering the earnings available for dividends.

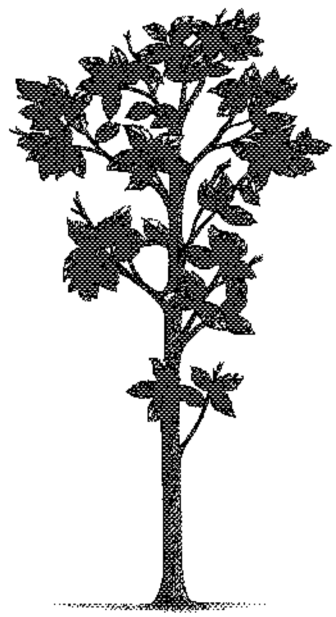
Recognizing this fact, the company in October reduced the common stock dividend approximately 39 percent to an annualized level of $1.20 per share. This level is one that we believe can be sustained and, over time, increased with the strong performance we expect from our various businesses. As anticipated, earnings per share for 1996 were $1.75, down from the $2.99 per share we reported in 1995.

These results are the product of steps — hard but necessary steps — we are taking to achieve the competitive, successful future we are confident lies ahead for your company. As we work to achieve that future, we remain fully aware of our responsibility to increase the value of your investment in PG&E Corporation.

We believe there is good reason for optimism that earnings, the dividend and stock price will rise over time and that PG&E Corporation will grow, because we are building that success on firm footings and a focused strategic vision. The foundation upon which our new corporation stands is a utility business which we are continuing to strengthen.

We undertook major programs in 1996 to upgrade the systems and facilities of our core electric distribution business. These programs will improve customer service, increase reliability and safety, and hone PG&E's competitiveness in the more deregulated energy market to come.

In 1996, California enacted Assembly Bill 1890. This law provides a clear legislative road map for achieving electric restructuring in California. It also reduces the financial uncertainties surrounding the restructuring by providing legislative assurance that the state's utilities will have a fair opportunity to recover significant costs associated with the transition to a competitive electric marketplace.



and the ability to create new beginnings...

Our gas and electric utility business continued to provide strong cash flow in 1996, which enabled us to repurchase a net of $236 million worth of PG&E common stock and retire a net of $384 million of long-term debt during the year. Over the next several years of transition to a restructured electric industry, we believe cash flow will remain strong as PG&E recovers its investments in utility generation. This will give the corporation substantial flexibility to invest in new business opportunities and continue to retire debt and buy back common stock.

And in our gas business, we continued over the year to expand into domestic and foreign markets through acquisitions of companies that operate in Texas, the Midwest and Eastern U.S., Australia and Canada.

In the energy world that is evolving, customers will be able to choose from an array of products and services provided by numerous competitive suppliers. Many customers will exercise their ability to choose. But as they do, many will not want the hassle of obtaining individual services from a wide variety of individual providers.

Like consumers who favor the convenience afforded by one-stop shopping at a supermarket, many customers will seek "energy supermarkets"—organizations that can integrate options into custom-tailored packages and "one-stop" total energy solutions.

PG&E Corporation's strategy is based on satisfying customers' desires for both choice and convenience. We intend to leverage the skill, experience and knowledge we have attained over a century of success in the electric and gas business to take full advantage of profitable opportunities as competitive markets open up.

Our plan is to pursue four lines of business.

Energy Services: This will be the major conduit between the customer and the energy choices PG&E Corporation and others in the market will offer. This unregulated business will help provide products and services from both the corporation's various gas and electric units and from competitive suppliers, packaging them in whatever combinations best meet individual customers' needs.

The energy services business will create value for customers by acting as their agent, helping them to make intelligent choices in a crowded and confusing marketplace of competing options.

It will be able to put together a wide range of energy services, obtaining gas and electricity from competitive producers, arranging for distribution and transmission service, providing customized energy billing and analysis, and offering energy retrofits, energy efficiency products and services, and facility improvements.

It also will market power quality services for customers whose manufacturing processes require uninterrupted power supplies. Through energy services, we will market our decades of experience in managing electric and gas facilities by contracting with utilities to help operate their distribution systems.

Distribution: The business of delivering gas and electricity to customers will remain a regulated function. Even if customers choose to purchase their electricity from other generators, the power will be delivered to their homes and businesses by the local distribution company. However, over time, there will be pressure to allow competitive suppliers to perform some functions that traditionally have been part of the distribution business.

Generation: While the amount of PG&E-owned electric generation will decline in the company's traditional service area, we will retain the Diablo Canyon nuclear power plant in California and will continue to develop, own and operate independent power plants in North America and possibly other selected regions of the world.

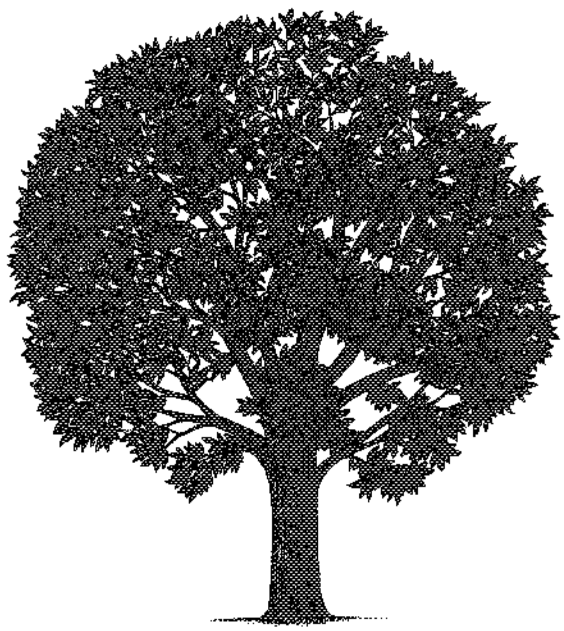
In 1995, the California Public Utilities Commission urged utilities to divest 50 percent of their fossil-fueled generation. In response to this request, PG&E in 1996 announced its intention to sell four of its fossil-fueled plants. These four plants represent half of PG&E's total fossil-fueled generating capacity.

U.S. Generating Company (USGen), our unregulated joint venture with Bechtel Enterprises, Inc., is a leading competitive power supplier. USGen and its affiliates have ownership interests and management responsibilities in 17 electric generation plants, which represent nearly 3,400 megawatts of generating capacity. The management success of these plants reflects USGen's leadership in clean generating technologies, as well as innovative operations, maintenance and environmental management techniques.

USGen is making substantial progress toward achieving its goals of continued long-term growth and profitability. By 2000, through development, acquisitions and concentrated marketing to meet its customers' needs, USGen intends to more than double the megawatts controlled in its current power plant portfolio. With effective management and efficient operation, USGen is confident it can continue to be a pace-setter in the evolving competitive marketplace.

Gas: We are pursuing the "midstream" portion of the gas market. This includes gas gathering, processing, storage, transportation and commodity marketing. This line of business presents attractive growth opportunities.

We estimate that $110 billion worth of new gas pipeline projects and facilities will be built worldwide between now and 2010.



which foster new growth...

STANLEY T. SKINNER

Customers will include utilities, electric generators, large industrial companies and local distribution organizations.

The corporation took a significant step forward in the midstream gas line of business in April of last year with the acquisition of the Queensland State Gas Pipeline in Australia. We see significant additional opportunities in Australia for this line of business.

In late 1996 and early 1997, we purchased Energy Source, Inc. (ESI) and Teco Pipeline Company. ESI markets natural gas supplies in the Midwest and Eastern U.S. and Canada. Teco Pipeline operates more than 1,000 miles of transmission and gas-gathering pipelines in Texas with a capacity of 1.5 billion cubic feet per day.

On January 31, 1997, we agreed to acquire the natural gas services business of Valero Energy Corporation, Valero Natural Gas Company, which operates a 7,500-mile natural gas pipeline system and eight natural gas processing plants in Texas. Valero's pipeline system has a capacity of more than 3 billion cubic feet of gas per day. Based in San Antonio, Texas, Valero's operations include the gathering, transporting, marketing and storage of natural gas; the processing, transporting and marketing of natural gas liquids; and the marketing of electricity.

Together, Valero, Teco and ESI will create one of the top ten gas marketing operations in the nation, with average daily sales volumes of 3.6 billion cubic feet per day in 1996.

We are optimistic about our ability to succeed in these lines of business. We have capable employees, abundant skills and a clear direction.

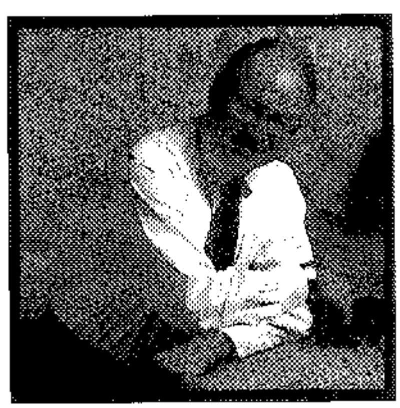
Our holding company is a new beginning, a new opportunity to build on our long record of outstanding performance in the energy industry.

For all of these reasons, we strongly believe that PG&E Corporation's prospects are promising and that we will continue to provide excellent value to our shareholders, our customers and the many communities we serve.

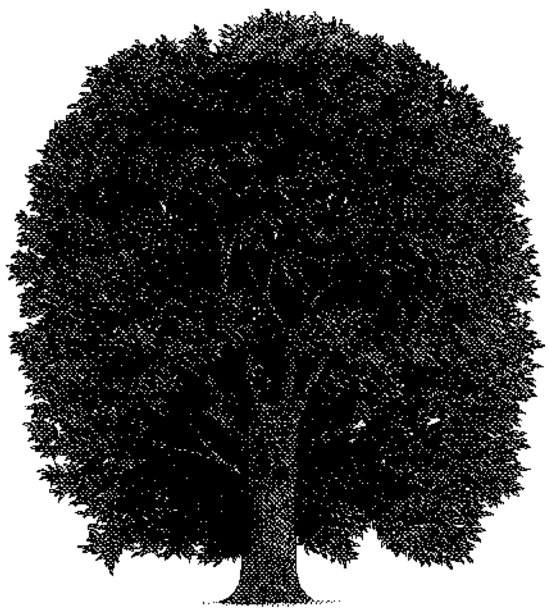
Stanley T. Skinner
Chairman of the Board and
Chief Executive Officer

Robert D. Glynn, Jr.
President and Chief
Operating Officer

February 10, 1997



ROBERT D. GLYNN, JR.



which ultimately endures.

Selected Financial Data

(in thousands, except per share amounts)	1996	1995	1994	1993	1992
For the Year					
Operating revenues	$ 9,609,972	$9,621,765	$10,350,230	$10,550,002	$10,315,713
Operating income	1,895,585	2,762,985	2,423,786	2,560,235	2,699,824
Net income	755,209	1,338,885	1,007,450	1,065,495	1,170,581
Earnings per common share	1.75	2.99	2.21	2.33	2.58
Dividends declared per common share	1.77	1.96	1.96	1.88	1.76
At Year End					
Book value per common share	$ 20.73	$ 20.77	$ 20.07	$ 19.77	$ 19.41
Common stock price per share	21.00	28.38	24.38	35.13	33.13
Total assets	26,129,925	26,850,290	27,708,564	27,145,899	24,188,159
Long-term debt and preferred stock and securities with mandatory redemption provisions (excluding current portions)	8,207,567	8,486,046	8,812,591	9,367,100	8,525,948

Matters relating to certain data above are discussed in Management's Discussion and Analysis of Consolidated Results of Operations and Financial Condition and in Notes to the Consolidated Financial Statements.

Effective January 1, 1997, Pacific Gas and Electric Company (PG&E) became a subsidiary of its new parent holding company, PG&E Corporation. PG&E's ownership interest in Pacific Gas Transmission Company (PGT) and PG&E Enterprises (Enterprises) was transferred to PG&E Corporation. PG&E's outstanding common stock was converted on a share-for-share basis into PG&E Corporation common stock. PG&E's debt securities and preferred stock were unaffected and remain securities of PG&E.

This holding company structure is intended to improve PG&E Corporation's ability to respond to new business opportunities and changes in the utility industry. It will enhance the financial separation of the California utility business from PG&E Corporation's other businesses and will provide greater financing flexibility.

The consolidated financial statements in this annual report include the accounts of PG&E and its wholly-owned and controlled subsidiaries (collectively, the Company) and, therefore, also represent the accounts of PG&E Corporation and its subsidiaries. PG&E provides generation, procurement, transmission, and distribution of electricity and natural gas to customers throughout most of Northern and Central California. PG&E is regulated by the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC), and the Nuclear Regulatory Commission, among others.

PGT and Enterprises, previously wholly-owned by PG&E, are now wholly-owned subsidiaries of PG&E Corporation. Through these subsidiaries, the Company is expanding its presence in the "midstream" portion of the gas business, the independent power generation business, and the energy services business.

The midstream portion of the gas business includes gas gathering, processing, storage, and transportation. The energy services business includes obtaining gas and electricity from competitive producers, arranging for distribution and transmission service, and providing customized energy billing and analysis, power quality assessments, energy efficiency products and services, and facility improvements.

PGT transports gas from the Canadian border to the California border and the Pacific Northwest and is regulated by the FERC. In 1996, PGT acquired PGT Queensland Gas Pipeline in Australia and Energy Source, the North American gas operations of Edisto Resources Corporation. In January 1997, PG&E Corporation acquired Teco Pipeline Company (Teco) in Texas. Teco owns a natural gas pipeline system in Texas, investments in gas gathering and processing facilities, and a gas marketing company in Houston. Also in January 1997, PG&E Corporation agreed to acquire Valero Natural Gas Company (Valero) (see Acquisitions and Sales below).

Enterprises, through its subsidiaries and affiliates, develops, owns, and operates unregulated electric and gas projects in the U.S. and around the world. Vantus Energy Corporation (Vantus), a subsidiary of Enterprises, markets gas and electricity commodities and provides energy services.

The following discussion of consolidated results of operations and financial condition includes forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," and similar expressions identify forward-looking statements involving risks and uncertainties.

These risks and uncertainties include but are not limited to the ongoing restructuring of the electric and gas industries and the outcome of regulatory proceedings related to that restructuring. The ultimate impacts of both increased competition and the changing regulatory environment on future results are uncertain, but both are expected to fundamentally change how the Company conducts its business. The outcome of these changes and other matters discussed below may cause future results to differ materially from historic results, or from results or outcomes currently expected or sought by the Company.

Competition and Changing Regulatory Environment: The electric and gas industries are undergoing 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.

Today, competitive pressures and emerging market forces are exerting an increasing influence over the structure of the gas and electric industries. Other companies are challenging the utilities' exclusive relationship with customers and are seeking to replace certain utility functions with their own. Customers, too, are asking for choice in their energy provider.

These pressures are causing a move from the existing regulatory framework to a framework under which competition would be allowed in certain segments of the gas and electric industries.

For several years, PG&E has been working with its regulators to achieve an orderly transition to competition and to ensure that PG&E has an opportunity to recover investments made under the traditional regulatory policies. In addition, PG&E has proposed alternative forms of regulation for those services for which prices and terms will not be determined by competition. These alternative forms include performance-based ratemaking (PBR) and other incentive-based alternatives. Over the next five years, a significant portion of PG&E's business will be transformed from the current utility monopoly to a competitive operation. This change will impact PG&E's financial results and may result in greater earnings volatility. During the transition period, PG&E expects the return on Diablo Canyon Nuclear Power Plant (Diablo Canyon) and certain other generation assets to be significantly lower than historical levels.

Electric Industry Restructuring: In 1995, the CPUC issued a decision that provides a plan to restructure California's electric utility industry. The decision acknowledges that much of utilities' current costs and commitments result from past CPUC decisions and that, in a competitive generation market, utilities would not recover some of these costs through market-based revenues. To assure the continued financial integrity of California utilities, the CPUC authorized recovery of these above-market costs, called "transition costs."

In 1996, California legislation was passed that adopts the basic tenets of the CPUC's restructuring decision, including recovery of transition costs. In addition, the legislation provides a 10 percent rate reduction for residential and small commercial customers by January 1, 1998, freezes electric customer rates for all other customers, and requires the accelerated recovery of transition costs associated with owned generation facilities. The legislation also establishes the operating framework for a competitive generation market.

The rate freeze will continue until the earlier of March 31, 2002, or until PG&E has recovered its transition costs (the transition period). The freeze will hold rates at 1996 levels for all customers except those receiving the 10 percent rate reduction. The rate freeze will hold the rates for these customers at the reduced level.

To achieve the 10 percent rate reduction, the legislation authorizes utilities to finance a portion of their transition costs with "rate reduction bonds." The maturity period of the bonds is expected to extend beyond the transition period. Also, the interest cost of the bonds is expected to be lower than PG&E's current cost of capital. Once this portion of transition costs is financed, PG&E would collect a separate tariff to recover principal, interest, and issuance costs over the life of the bonds from residential and small commercial customers. The combination of the longer maturity period and the reduced interest costs will lower the amounts paid by these customers each year during the transition period thereby achieving the 10 percent reduction in rates.

During 1997, differences between authorized and actual base revenues and differences between the actual cost of electric generation and the revenue designated for recovery of such revenues or costs will be recorded in balancing accounts. Any residual balance will be available for transition cost recovery. During 1997, amounts recorded in balancing accounts will be subject to a reasonableness review by the CPUC.

Absent the rate freeze, PG&E's rates would be expected to decline under existing cost-based ratemaking methodologies. The most significant reasons for the decrease in cost-based rates are the declining cost of power committed under certain purchase power contracts, the reduction in the Diablo Canyon price for power under the existing CPUC-approved settlement, and the decline in uncollected electric balancing accounts.

Transition Cost Recovery: The legislation authorizes the CPUC to determine the costs eligible for recovery as transition costs. The amount of costs will be based on the aggregate of above-market and below-market values of utility-owned generation assets and obligations. PG&E has proposed that costs eligible for transition cost recovery include: (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and currently collected through rates) and future costs, such as costs related to plant removal, (2) above-market costs associated with purchase power obligations with Qualifying Facilities (QFs) and other Power Purchase Agreements, and (3) generation-related regulatory assets and obligations. PG&E cannot determine the exact amount of sunk costs that will be above market and recoverable as transition costs until a market valuation process (appraisal or sale) is completed for each generation facility. This process will be completed during the transition period.

In compliance with the CPUC's restructuring decision and the restructuring legislation, PG&E has filed numerous regulatory applications and proposals that detail its transition cost recovery plan. PG&E's recovery plan includes: (1) separation or unbundling of its previously approved cost-of-service revenue requirement for its electric operations into distribution, transmission, public purpose programs (PPPs), and generation, (2) accelerated recovery of transition costs, and (3) development of a ratemaking mechanism to track and match revenues and cost recovery during the transition period.

The unbundling of PG&E's revenue requirement enables it to separate revenue provided by frozen rates into transmission, distribution, PPPs, and generation. As proposed, revenues collected under frozen rates would be assigned to transmission, distribution, and PPPs based upon their respective cost of service. Revenue would also be provided for other costs, including nuclear decommissioning, rate-reduction-bond debt service, the on-going cost of generation, and transition cost recovery. The combination of a rate freeze and decreasing costs, based upon existing ratemaking and cost recovery periods, provides an adequate amount of revenue available for full transition cost recovery.

PG&E has proposed to accelerate recovery for certain transition costs related to generation facilities, including Diablo Canyon. Additionally, PG&E would receive a reduced return on common equity associated with generation plant assets for which recovery is accelerated. The lower return reflects the reduced risk associated with the shorter amortization period and increased certainty of recovery.

In applying its cost recovery plan to Diablo Canyon, PG&E has proposed to replace the existing settlement prices with: (1) a sunk cost revenue requirement to recover fixed costs, including a return on these costs, and (2) a PBR mechanism to recover the facility's variable costs and capital addition costs. As proposed, the sunk cost revenue requirement would accelerate recovery of Diablo Canyon sunk costs from a twenty-year period ending in 2016 to a five-year period beginning in 1997 and ending in 2001. The related return on common equity associated with Diablo Canyon sunk costs would be reduced to 90 percent of PG&E's long-term cost of debt. PG&E's authorized long-term cost of debt was 7.52 percent in 1996. The reduced rate of return combined with a shorter recovery period would result in an estimated $4 billion decrease in the net present value of PG&E's future revenues from Diablo Canyon operations. If the proposed cost recovery plan for Diablo Canyon were adopted during 1996, Diablo Canyon's 1996 reported net income would have been reduced by $350 million ($0.85 per share).

Most transition costs must be recovered by March 1, 2002. However, the legislation authorizes recovery of certain transition costs after that time. These costs include: (1) certain employee-related transition costs, (2) payments under existing QF and power purchase contracts, and (3) unrecovered implementation costs. Excluding these exceptions, any transition costs not recovered during the transition period will be absorbed by PG&E. Nuclear decommissioning costs, which are not considered transition costs, will be recovered through a CPUC authorized charge. During the transition period, this charge will be incorporated into the frozen rates. After the transition period, customers will be assessed a surcharge until the nuclear decommissioning costs are fully recovered.

PG&E's ability to recover its transition costs during the transition period will be dependent on several factors. These factors include: (1) the extent to which application of the current regulatory framework established by the restructuring legislation will continue to be applied, (2) the amount of transition costs approved by the CPUC, (3) the market value of PG&E's generation plants, (4) future sales levels, (5) fuel and operating costs, (6) the market price of electricity, and (7) the ratemaking methodology adopted for Diablo Canyon. Considering its current evaluation of these factors, PG&E believes it will recover its transition costs and that its owned generation plants are not impaired. However, a change in these factors could affect the probability of recovery of transition costs and result in a material loss.

PG&E has proposed to implement portions of its transition cost recovery plan in 1997. The CPUC decision on PG&E's 1997 Energy Cost Adjustment Clause (ECAC) application would decrease PG&E's 1997 revenue requirement by $720 million. This decrease would be partially offset by a $160 million revenue requirement increase, provided by the legislation, for purposes of enhancing transmission and distribution system safety and reliability. This increase was approved by the CPUC as part of PG&E's transition cost recovery plan.

Given the electric customer rate freeze, the $560 million net revenue requirement decrease resulting from the consolidation of the ECAC decision and the revenue requirement increase contemplated in the cost recovery plan would be available for transition cost recovery. The proposed accelerated recovery of Diablo Canyon would absorb an estimated $400 million of this available revenue requirement. The remaining revenue requirement would be available to recover other transition costs.

Competitive Market Framework: In addition to transition cost recovery, the legislation establishes the operating framework for the competitive generation market in California. This framework will consist of a power exchange (PX) and an independent system operator (ISO). The PX, open to all electricity providers, will conduct a competitive auction to establish the price of electricity. The ISO will ensure system reliability and provide all electricity generators with open and comparable access to transmission and distribution services.

Although the PX will be available to all customers, the legislation allows customers to bypass the PX by entering into direct access contracts with other electricity providers, subject to a nonbypassable transition charge. This direct access will be available to certain customers by January 1, 1998, and will be phased in for all remaining customers through December 31, 2001. During the transition period, PG&E will bill direct access customers based upon fully bundled frozen rates. Direct access customers' bills from PG&E would then be reduced by an amount based on the PX price and the customers' electric usage. These customers can be billed for their usage directly by their chosen supplier, or the supplier may contract with PG&E to perform this billing. During the transition period, these customers' overall electric rates will vary only to the extent that their direct access contract price differs from the PX price.

To prevent undue influence on the PX price by any participant in the competitive framework, PG&E has indicated it is willing to proceed with divestiture of at least 50 percent of its fossil-fueled power plants as directed by the CPUC. PG&E has filed an application seeking approval from the CPUC to sell four plants before the end of 1997. The book value for these plants is approximately $400 million, and together they generate approximately 10 percent of PG&E's total electric sales. PG&E proposes to recover any shortfall in proceeds from divestiture of these plants as a transition cost. Accordingly, the Company does not expect any adverse impact on its results of operations from the sale of these plants.

In addition to the CPUC's electric industry restructuring discussed above, the FERC has required utilities to provide wholesale open access to electric transmission systems on terms that are comparable to the way utilities use their own systems. PG&E's open access tariff, filed in July 1996, provides access to any eligible party interested in wholesale transmission service over PG&E's transmission system. The FERC also reaffirmed its intention to permit utilities to recover any legitimate, verifiable, and prudently incurred costs stranded as a result of customers taking advantage of wholesale open access orders to meet their power needs from other sources. Further, the FERC asserted that it has jurisdiction over the transmission component of retail direct access.

By developing the PX and the ISO and by implementing direct access to generation and open access to transmission, regulators have established the operating framework of the competitive generation and wholesale transmission markets. Although this framework will fundamentally change the way PG&E does business, the Company does not believe that the changes will have a material adverse impact on its ability to recover transition costs.

Accounting for the Effects of Regulation: PG&E accounts 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 the Company to record certain regulatory assets and liabilities that would not be recorded under generally accepted accounting principles for nonregulated entities. In addition, SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," requires that regulatory assets be written off when they are no longer probable of recovery and that impairment losses be recorded for long-lived assets when related future cash flows are less than the carrying value of the asset.

As a result of applying the provisions of SFAS No. 71, PG&E has accumulated approximately $1.6 billion of regulatory assets attributable to electric generation at December 31, 1996.

The net investments in Diablo Canyon and the other generation assets were $4.5 billion and $2.7 billion, respectively, at December 31, 1996. The net present value of above-market QF power purchase obligations is estimated to be $5.3 billion at January 1, 1998, at an assumed PX price of $0.025 per kilowatt-hour (kWh) beginning in 1997 and escalating at 3.2 percent per year.

PG&E believes that the restructuring legislation establishes a definitive transition to market-based pricing for electric generation. Incorporating the effects of the PX and direct access, this transition includes cost-of-service based ratemaking. In addition, PG&E's generation-related transition costs will be collected through a nonbypassable charge. Based on this structure, PG&E believes it will continue to meet the requirements of SFAS No. 71 throughout the transition period.

At the conclusion of the transition period, PG&E believes it will be at risk to recover its generation costs through market-based revenues. At that time, PG&E expects to discontinue the application of SFAS No. 71 for the electric generation portion of its business. Since PG&E anticipates it will have recovered all transition costs required to be recovered during the transition period, including generation-related regulatory assets and above-market investments in net plant, PG&E does not expect a material adverse impact on its financial position or results of operations from discontinuing the application at that time.

As a result of the CPUC's restructuring decision and California's electric industry restructuring legislation, the Securities and Exchange Commission (SEC) has begun inquiries regarding the appropriateness of the continued application of SFAS No. 71 by California utilities to their electric generation businesses. As discussed above, PG&E believes it currently meets and will continue to meet the requirements to apply SFAS No. 71 during the transition period. In the event that the SEC concludes that the current regulatory and legal framework in California no longer meets the requirements to apply SFAS No. 71 to the generation business, the Company would reevaluate the financial impact of electric industry restructuring and a material write-off could occur.

Given the current regulatory environment, PG&E's electric transmission and distribution businesses are expected to remain regulated and, as a result, will continue application of the provisions of SFAS No. 71.

Gas Industry Restructuring: Restructuring of the natural gas industry on both the national and the state level has given customers greater options in meeting their gas supply needs. PG&E's customers may buy commodity gas directly from competing suppliers and purchase transmission- and distribution-only services from PG&E. Transmission and distribution services have remained "bundled," or sold together at a combined rate, within the state. PGT, as an interstate pipeline, has provided nondiscriminatory transmission-only service since 1993 and no longer sells commodity gas.

Most of PG&E's industrial and larger commercial (noncore) customers purchase their commodity gas from marketers and brokers. Substantially all residential and smaller commercial (core) customers continue to buy commodity gas as well as transmission and distribution from PG&E as a bundled service.

In 1995 and 1996, PG&E actively pursued changes in the California gas industry in an effort to promote competition and increase options for all customers, as well as to position itself for the competitive marketplace. In 1996, PG&E submitted to the CPUC the Gas Accord Settlement (Accord). The Accord is the result of an extensive negotiation process, begun in 1995, among a broad coalition of customer groups and industry participants. The Accord must be approved by the CPUC before it can be implemented. A CPUC decision is expected in 1997.

The Accord consists of three broad initiatives:

(1) The Accord would separate, or "unbundle," PG&E's gas transmission and storage services from its distribution services and would change the terms of service and rate structure for gas transportation. Unbundling would give customers the opportunity to select from a menu of services offered by PG&E and would enable them to pay only for the services they use. PG&E would be at risk for variations in revenues resulting from differences between actual and forecasted transmission throughput. PG&E would also continue to provide cost-of-service based distribution service, much as it does today.

(2) The Accord would increase opportunities for PG&E's core customers to purchase gas from competing suppliers and, therefore, could reduce PG&E's role in procuring gas for such customers. However, PG&E would continue to procure gas as a regulated utility supplier for those customers who request it. The Accord also would establish principles for continuing negotiations between PG&E and California gas producers for

the mutual release of supply contracts and the sale of gas gathering facilities. Also related to PG&E's procurement activities, PG&E has proposed that traditional reasonableness reviews of its core gas costs be replaced with a core procurement incentive mechanism (CPIM) for the period June 1, 1994, through 2002. Under the CPIM, PG&E would be able to recover its gas commodity and interstate transportation costs and would receive benefits or be penalized depending on whether its actual core procurement costs were within, below, or above a "tolerance band" constructed around market benchmarks. Actual core procurement costs measured for the period June 1, 1994, through December 31, 1996, have generally been within the CPIM "tolerance band." The CPIM proposal also requests authorization to use derivative financial instruments to reduce the risk of gas price and foreign currency fluctuations. Gains, losses, and transaction costs associated with the use of derivative financial instruments would be included in the purchased gas account and the measurement against the benchmarks.

(3) The Accord would resolve various regulatory issues (see further discussion in Note 3 to the Consolidated Financial Statements) including:

- the disallowances ordered by the CPUC in connection with PG&E's 1988 through 1995 gas reasonableness proceedings;
- the recovery of certain capital costs associated with the PG&E portion of the PGT/PG&E Pipeline Expansion;
- the recovery of costs related to PG&E's capacity commitments with Transwestern Pipeline Company through 2002; and
- the recovery, through PG&E's interstate transition cost surcharge, of fixed demand charges paid to El Paso Natural Gas Company and PGT for firm capacity held by PG&E on behalf of its customers.

As of December 31, 1996, PG&E has reserved approximately $527 million, including $182 million reserved during 1996, relating to its gas regulatory issues and gas capacity commitments, the majority of which are addressed by the Accord. PG&E believes the ultimate resolution of these matters, whether through approval of the Accord or otherwise, will not have a material adverse impact on its financial position or future results of operations.

Acquisitions and Sales: The Company has developed strategies to focus on the unregulated independent power generation market, the unregulated energy services market, and the regulated and unregulated "midstream" portions of the gas market. As a result of this focus, the Company has been acquiring related businesses and disposing of unrelated businesses.

Enterprises participates in multiple domestic and international energy businesses. The majority of Enterprises' domestic investments are in nonregulated energy projects through U.S. Generating Company (USGen), a joint venture with Bechtel Enterprises, Inc. (Bechtel). USGen and its affiliates develop, own, and operate power plants in the United States.

Enterprises' entry into the international market was also made in partnership with Bechtel. Enterprises and Bechtel formed International Generating Company, Ltd., (InterGen) which develops, owns, and operates international electric generation projects. However, in November 1996, Enterprises and Bechtel reached an agreement for Bechtel to acquire Enterprises' interest in InterGen. The Company expects to complete the sale in the first quarter of 1997 and realize an after-tax gain. Enterprises has refined its international strategy to focus on select countries and to concentrate on end-use energy customers.

In 1995, Enterprises formed Vantus, a retail energy services provider, to assist customers in locating the most cost-effective electric and gas products and services. Vantus' energy services include power marketing for industrial and large commercial businesses nationwide. In 1996, Vantus opened new offices in the western United States to establish a presence and market its services in emerging energy markets.

Also in 1995, Enterprises sold DALEN Corporation (DALEN). The sales price was $455 million, including $340 million cash and the assumption of $115 million of existing debt. The sale resulted in an after-tax gain of approximately $13 million.

The Company is pursuing gas-related opportunities as the gas industry continues to evolve. In July 1996, the Company, through its subsidiary PGT, purchased PGT Queensland State Gas Pipeline, a 389-mile natural gas transportation system in the Australian state of Queensland. The final purchase price was $136 million.

In December 1996, PGT entered the unregulated gas marketing arena with the purchase of Energy Source (ESI), the North American gas marketing operations of Edisto Resources Corporation for approximately $23 million. The purchase included most of ESI's existing contracts for the purchase, sale, and transportation of natural gas and natural gas futures. In 1996, ESI generated over $1.1 billion in gas marketing revenues, of which $283 million was earned in December 1996.

In January 1997, PG&E Corporation acquired Teco and its subsidiaries for approximately $380 million. Teco is an owner of a 500-mile natural gas pipeline system in Texas. Teco also has investments in gas gathering and processing facilities and owns a gas marketing company in Houston.

Also in January 1997, PG&E Corporation agreed to acquire Valero. Valero's operations include the gathering, transportation, marketing, and storage of natural gas, the processing, transportation, and marketing of natural gas liquids, and the marketing of electric power. Valero operates approximately 7,500 miles of natural gas pipeline and also owns and operates 536 miles of natural gas liquid pipeline and eight natural gas processing plants in Texas. PG&E Corporation will acquire Valero for approximately $1.5 billion, comprised of approximately $720 million in PG&E Corporation common stock and the assumption of debt and liabilities. The acquisition is expected to be completed by mid-1997 and is subject to applicable regulatory and shareholder approvals.

All of the above acquisitions have been or will be accounted for using the purchase method of accounting.

Results of Operations: The Company's results of operations were derived from three business lines: utility (excluding Diablo Canyon and including PGT's gas pipeline operations), Diablo Canyon, and diversified operations (principally, Enterprises and ESI). The results of operations and total assets for 1996, 1995, and 1994 are reflected in the following table and discussed below:

(in millions, except per share amounts)	Utility	Diablo Canyon[1]	Diversified Operations	Total
1996				
Operating revenues	$ 7,411	$1,789	$ 410	$ 9,610
Operating expenses	6,465	791	458	7,714
Operating income (loss) before income taxes	$ 946	$ 998	$ (48)	$ 1,896
Net income (loss)	$ 292	$ 497	$(34)[2]	$ 755
Earnings per common share	$ .65	$ 1.18	$ (.08)	$ 1.75
Total assets at year end	$19,283	$5,413	$1,434	$26,130
1995				
Operating revenues	$ 7,601	$1,845	$ 176	$ 9,622
Operating expenses	5,820	816	223	6,859
Operating income (loss) before income taxes	$ 1,781	$1,029	$ (47)	$ 2,763
Net income	$ 820	$ 507	$ 12[2]	$ 1,339
Earnings per common share	$ 1.80	$ 1.16	$ .03	$ 2.99
Total assets at year end	$20,090	$5,717	$1,043	$26,850
1994				
Operating revenues	$ 8,232	$1,870	$ 248	$10,350
Operating expenses	6,732	914	280	7,926
Operating income (loss) before income taxes	$ 1,500	$ 956	$ (32)	$ 2,424
Net income	$ 539	$ 461	$ 7[2]	$ 1,007
Earnings per common share	$ 1.15	$ 1.04	$ .02	$ 2.21
Total assets at year end	$20,295	$5,978	$1,436	$27,709

[1] See Note 4 to the Consolidated Financial Statements for discussion of allocations.
[2] Includes non-operating income resulting from property sales, partnership earnings, and investment income.

Earnings Per Common Share: Earnings per common share were $1.75, $2.99, and $2.21 for 1996, 1995, and 1994, respectively. Utility earnings in 1996 were lower than 1995, reflecting revenue reductions ordered in the 1996 General Rate Case (GRC) and other related rate proceedings and reflecting several one-time charges. The revenue reductions resulted from a lower cost of capital, lower capital expenditures, and reductions in authorized expense levels. Actual maintenance and other operating expenses for distribution and customer-related services increased in 1996 and exceeded levels authorized in the 1996 GRC. These increases were primarily attributable to several projects related to transmission and distribution system reliability, and improved customer-related services. Additionally, PG&E recorded a charge of $.26 per common share for contingencies related to gas transportation commitments and recorded a charge of $.19 per common share for settlement of litigation. (See Operating Expenses below and Notes 3 and 13 to the Consolidated Financial Statements.) Finally, the Company recorded a charge of $.09 per common share for write-downs of nonregulated investments.

Earnings per common share for 1995 were higher than 1994 due to fewer one-time charges against earnings than in 1994 (see Operating Expenses below). In addition, there were fewer scheduled refueling outages at Diablo Canyon in 1995, compared with 1994.

On a consolidated basis, the Company earned 8.5, 14.6, and 11.1 percent returns on average common stock equity for the years ended December 31, 1996, 1995, and 1994, respectively. PG&E has received a CPUC decision which authorizes, for 1997, a return on common equity of 11.6 percent and an overall rate of return of 9.45 percent. However, PG&E has filed a proposal with the CPUC to accelerate recovery of certain transition costs related to generation facilities, including Diablo Canyon. Additionally, PG&E would receive a reduced return on common equity associated with generation plant assets for which recovery is accelerated. This return would equal 90 percent of PG&E's long-term cost of debt. PG&E's authorized long-term cost of debt was 7.52 percent in 1996. (See Electric Industry Restructuring above.)

Common Stock Dividend: The Company's common stock dividend is based on a number of financial considerations, including sustainability, financial flexibility, and competitiveness with investment opportunities of similar risk. The Company's current quarterly common stock dividend is $.30 per common share which corresponds to an annualized dividend of $1.20 per common share. This represents a decrease from the previous annualized dividend of $1.96 per common share. The Company has identified a dividend payout ratio objective (dividends declared divided by earnings available for common stock) of between 50 and 65 percent (based on earnings exclusive of nonrecurring adjustments).

Operating Revenues: Operating revenues in 1996 decreased slightly from 1995. The decreases in utility revenues as ordered in the 1996 GRC, discussed above, and in Diablo Canyon revenues were offset by increased revenues from diversified operations. Revenues from Diablo Canyon decreased due to a decline in the generation price, as provided in the Diablo Canyon rate case settlement as modified in 1995 (Diablo Settlement) (see Note 4 to the Consolidated Financial Statements). This decline was partially offset by higher net generation, which was a result of fewer scheduled refuelings in 1996 compared to 1995. Revenues from diversified operations increased primarily due to the purchase of ESI in December 1996. This purchase created $283 million of revenue but was partially offset by a decline in revenue due to the sale of DALEN in 1995. (See Acquisitions and Sales above.)

Operating revenues for 1995 decreased $728 million from 1994. The decrease in utility revenues was primarily due to a decrease in electric energy costs caused by favorable hydroelectric conditions and lower natural gas prices. Diablo Canyon operating revenues decreased due to a decrease in the generation price as provided in the modified Diablo Settlement (see Note 4 to the Consolidated Financial Statements for further discussion). This decrease was partially offset by favorable operating revenues from Diablo Canyon resulting from fewer refueling days in 1995. Revenues from diversified operations decreased $72 million in 1995 compared to 1994 primarily due to the sale of DALEN in June 1995.

Operating Expenses: Operating expenses increased $855 million in 1996 compared to 1995, primarily due to: (1) a charge of $182 million for contingencies related to gas transportation commitments, (2) increases in the cost of gas due to price increases, (3) increases in purchased power prices and volumes, (4) increases in maintenance and other operating expenses for transmission and distribution system reliability and for improved customer-related services, (5) increases in litigation costs, and (6) an increase in the cost of gas for resale due to the purchase of ESI in December 1996. The cost of gas increase from the purchase of ESI was offset by revenues as discussed above.

Operating expenses decreased $1,067 million in 1995 compared to 1994 primarily due to decreased electric costs caused by favorable hydroelectric conditions, decreased natural gas prices, and no workforce reduction charges in 1995. (See Note 10 to the Consolidated Financial Statements.)

Other Income and (Expense): Other income and expense changed in 1996 compared to 1995 primarily due to write-downs of certain nonregulated investments.

Liquidity and Capital Resources:

The Company's capital requirements are funded from cash provided from operations and, to the extent necessary, external financing. The Company's policy is to finance its assets with a capital structure that minimizes financing costs, maintains financial flexibility, and complies with regulatory guidelines. Based on cash provided from operations and its capital requirements, the Company may repurchase equity and long-term debt in order to manage the overall balance of its capital structure.

Debt: In 1996, 1995, and 1994, the Company redeemed or repurchased $1,113, $758, and $202 million, respectively, of long-term debt to manage the overall balance of the Company's capital structure. Long-term debt maturing during 1996, 1995, and 1994 was not refinanced.

Included in the 1996 repurchases is $988 million of variable and fixed interest rate pollution control mortgage bonds and loan agreements which were replaced with variable interest rate pollution control loan agreements. Also in 1996, the Company entered into additional loan agreements of $92 million to finance the PGT acquisition of PGT Queensland State Gas Pipeline. In addition, the Company used its cash balances to reduce short-term borrowings by $115 million in 1996.

In 1995, PGT issued $400 million of bonds and $70 million of medium-term notes. In addition, PGT issued commercial paper which is classified as long-term debt. This classification is based upon the availability of committed credit facilities expiring in 2000 and management's intent to maintain such amounts in excess of one year. The commercial paper outstanding was $108 and $109 million at December 31, 1996, and 1995, respectively. Substantially all of the proceeds of PGT's debt issued in 1995 were used to refinance outstanding debt.

PG&E issues short-term debt (principally commercial paper) to fund fuel oil, nuclear fuel, and gas inventories, unrecovered balances in balancing accounts, and cyclical fluctuations in daily cash flows. At December 31, 1996, and 1995, PG&E had $681 and $796 million, respectively, of commercial paper outstanding. PG&E maintains a $1 billion revolving credit facility which primarily provides support for PG&E's commercial paper issuance. At maturity, commercial paper can be either reissued or replaced with borrowings from this credit facility. The facility can also be used for general corporate purposes. There were no borrowings under this facility in 1996, 1995, or 1994.

In January 1997, PG&E Corporation established a $500 million revolving credit facility in order to provide for corporate short-term liquidity needs and other purposes.

As discussed in electric industry restructuring above, to achieve the 10 percent rate reduction for residential and small commercial customers, the electric industry restructuring legislation authorizes utilities to finance a portion of the transition costs with "rate reduction bonds." PG&E expects to work with state authorities to coordinate the issuance of up to $2.5 billion of these bonds by a special purpose entity. Once issued, PG&E would collect, on behalf of the special purpose entity, a separate tariff to recover principal, interest, and issuance costs over the life of the bonds from residential and small commercial customers. PG&E does not expect to secure the bonds with the Company's assets or unrelated future revenues.

Equity: In 1996, 1995, and 1994, PG&E received $220, $140, and $274 million, respectively, in proceeds from the sale of common stock under the employee Savings Fund Plan, the Dividend Reinvestment Plan, and the employee Long-term Incentive Program.

Since 1993, the Board has authorized the Company to repurchase up to $2 billion of its common stock on the open market or in negotiated transactions. These repurchases are funded by internally generated funds and are used to manage the overall balance of common stock in the Company's capital structure. Through December 31, 1996, the Company had repurchased approximately $1.5 billion of its common stock under this program. Repurchases for 1996, 1995, and 1994 were $455, $601, and $182 million, respectively.

In 1996, PG&E did not redeem or repurchase any preferred stock. In 1995 and 1994, PG&E redeemed or repurchased $331 and $75 million, respectively, of its higher-cost preferred stock. In 1994, PG&E issued $62 million of preferred stock.

PG&E is limited as to the amount of dividends that it may pay to PG&E Corporation based on PG&E's regulatory capital structure authorized by the CPUC. PG&E's equity shall be retained such that, on average, the capital structure authorized by the CPUC is maintained. This restriction is not expected to affect PG&E Corporation's ability to meet its cash obligations.

Other Capital: In 1995, PG&E through its wholly-owned subsidiary, PG&E Capital I, issued $300 million of cumulative quarterly income preferred securities. Net proceeds were used to redeem and repurchase higher-cost preferred stock.

Investing Activities: The Company's estimated capital requirements for the next three years are shown below:

Year ended December 31, (in millions)	1997	1998	1999
Utility (including PGT)	$1,773	$1,825	$1,705
Diablo Canyon	38	39	41
Diversified operations	211	80	172
Total capital expenditures	2,022	1,944	1,918
Maturing debt and sinking funds	210	660	270
Total capital requirements	$2,232	$2,604	$2,188

Utility and Diablo Canyon expenditures will be primarily for improvements to the Company's facilities to enhance their efficiency and reliability, to extend their useful lives, and to comply with environmental laws and regulations.

Expenditures for diversified operations (consisting primarily of Enterprises) include capital contributions for Enterprises' equity share of generating facility projects. Ongoing capital expenditures for Teco are included in diversified operations in the above estimated capital requirements.

In addition to the above, the Company, in January 1997, has acquired Teco for approximately $380 million, consisting of a note payable of $61 million and $319 million of PG&E Corporation's common stock. Further, the Company, in January 1997, agreed to acquire Valero for approximately $1.5 billion, consisting of approximately $720 million of PG&E Corporation's common stock and the assumption of debt and liabilities. The Company has other commitments as discussed in Notes 3 and 12 to the Consolidated Financial Statements.

In December 1995, the Company had a balance of $734 million of cash and cash equivalents due to the sale of DALEN and the retention of cash for potential investments.

Risk Management: Due to the changing business environment, the Company's exposure to risks associated with changes in energy commodity prices, interest rates, and foreign currencies is increasing. To manage these risks, the Company has adopted a price risk management policy and established an officer-level price risk management committee. The Company's price risk management committee oversees implementation of the policy, approves each price risk management program, and monitors compliance with the policy.

The Company's price risk management policy and procedures adopted by the committee establish guidelines for implementation of price risk management programs. Such programs may include the use of energy and financial derivatives. (A derivative is a contract whose value is dependent on or derived from the value of some underlying asset.) Additionally, the Company's policy allows derivatives to be used for hedging and non-hedging purposes. (Hedging is the process of protecting one transaction by means of another to reduce price risk.) Both hedging and non-hedging activities are limited to those specifically approved by the committee only after appropriate controls and procedures are put in place to measure, monitor, and control the risk of such activities. The Company's policy prohibits the use of derivatives whose payment formula includes a multiple of some underlying asset.

In 1996, the Company approved and implemented interest rate and foreign exchange risk management programs, applied for regulatory approval to use energy derivatives to manage commodity price risk in its utility business, and acquired certain natural gas marketing operations which engage in both hedging and non-hedging derivative transactions. Gains and losses associated with price risk management activities during 1996 were immaterial.

Environmental Matters: The Company's projected expenditures for environmental protection are subject to periodic review and revision to reflect changing technology and evolving regulatory requirements. Capital expenditures for environmental protection are currently estimated to be approximately $36, $50, and $72 million for 1997, 1998, and 1999, respectively. Expenditures during these years will be primarily for nitrogen oxide (NOx) emission reduction projects at the Company's fossil fuel generating plants and natural gas compressor stations. Pursuant to federal and state legislation, local air districts have adopted rules that require reductions in NOx emissions. These rules are subject to continued review and modification by the local air districts in which PG&E operates. The Company currently estimates that compliance with NOx rules could require capital expenditures of up to $360 million over the next ten years.

On an ongoing basis, the Company assesses compliance with laws and regulations related to hazardous substance remediation. The Company has an accrued liability at December 31, 1996, of $170 million for remediation costs at sites where such costs are probable and quantifiable. The costs at identified sites may be as much as $400 million if, among other things, other potentially responsible parties are not financially able to contribute to these costs, or identifiable possible outcomes change. The Company will seek recovery of prudently incurred compliance costs through ratemaking procedures approved by the CPUC. The Company has recorded a regulatory asset at December 31, 1996, of $146 million for recovery of these costs in future rates. Additionally, the Company will seek recovery of costs from insurance carriers and from other third parties. (See Note 13 to the Consolidated Financial Statements.)

Effective January 1, 1997, the Company will adopt the provisions of the American Institute of Certified Public Accountants' Statement of Position (SOP) 96-1, Environmental Remediation Liabilities. This SOP provides authoritative guidance for recognition, measurement, display, and disclosure of environmental remediation liabilities in financial statements. The adoption of SOP 96-1 is not expected to have a material adverse impact on the Company's financial position or results of operations.

Legal Matters: In the normal course of business, the Company is named as a party in a number of claims and lawsuits. Substantially all of these have been litigated or settled with no material adverse impact on either the Company's results of operations or financial position. In addition, the Company believes that the litigation or settlement of pending claims and lawsuits will not have a material adverse impact on its results of operations or financial position. See Note 13 to the Consolidated Financial Statements for further discussion of significant pending legal matters.

Accounting for Decommissioning Expense: In 1996, the Financial Accounting Standards Board issued an exposure draft on a proposed SFAS entitled "Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets." If this exposure draft is adopted: (1) annual expense for power plant decommissioning could increase, and (2) the estimated total cost for power plant decommissioning could be recorded as a liability, with recognition of an increase in the cost of the related power plant, rather than accrued over time as accumulated depreciation. The Company does not believe that this change, if implemented as proposed, would have a material adverse impact on its results of operations due to its current and future ability to recover decommissioning costs through rates. (See Note 2 to the Consolidated Financial Statements for discussion of electric industry restructuring.)

Inflation: The Company's rates are designed to recover operating and historical plant investment costs. Financial statements, which are prepared in accordance with generally accepted accounting principles, report operating results in terms of historic costs and do not evaluate the impact of inflation.

Inflation affects the Company's construction costs, operating expenses, and interest charges. Due to the Company's five-year electric rate freeze, electric revenues will not reflect the impact of inflation. However, inflation at the levels currently being experienced is not expected to have a material adverse impact on the Company's future results of operations.

Statement of Consolidated Income

Year ended December 31, (in thousands, except per share amounts)	1996	1995	1994
Operating Revenues			
Electric utility	$7,160,215	$7,386,307	$ 8,021,547
Gas utility	2,039,802	2,059,117	2,081,062
Diversified operations	409,955	176,341	247,621
Total operating revenues	9,609,972	9,621,765	10,350,230
Operating Expenses			
Cost of electric energy	2,303,488	2,116,840	2,570,723
Cost of gas	761,837	333,280	583,356
Maintenance and other operating	2,118,174	1,799,781	1,855,585
Depreciation and decommissioning	1,221,952	1,360,118	1,397,470
Administrative and general	1,016,439	971,576	973,302
Workforce reduction costs	—	(18,195)	249,097
Property and other taxes	292,497	295,380	296,911
Total operating expenses	7,714,387	6,858,780	7,926,444
Operating Income	1,895,585	2,762,985	2,423,786
Interest income	72,900	72,524	79,643
Interest expense	(639,823)	(688,408)	(729,207)
Other income and (expense)	(18,459)	87,073	69,995
Pretax Income	1,310,203	2,234,174	1,844,217
Income Taxes	554,994	895,289	836,767
Net Income	755,209	1,338,885	1,007,450
Preferred dividend requirement and redemption premium	33,113	70,288	57,603
Earnings Available for Common Stock	$ 722,096	$1,268,597	$ 949,847
Weighted Average Common Shares Outstanding	412,542	423,692	429,846
Earnings Per Common Share	$ 1.75	$ 2.99	$ 2.21
Dividends Declared Per Common Share	$ 1.77	$ 1.96	$ 1.96

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

Statement of Consolidated Cash Flows

Year ended December 31, (in thousands)	1996	1995	1994
Cash Flows From Operating Activities			
Net income	$ 755,209	$1,338,885	$1,007,450
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and decommissioning	1,221,952	1,360,118	1,397,470
Amortization	93,948	89,353	95,331
Deferred income taxes and tax credits—net	(149,990)	(116,069)	15,312
Other deferred charges	94,475	61,700	32,740
Other noncurrent liabilities	113,244	(17,218)	181,902
Noncurrent balancing account liabilities and other deferred credits	(185,390)	(69,787)	316,920
Net effect of changes in operating assets and liabilities			
Accounts receivable	(46,368)	212,515	(116,936)
Regulatory balancing accounts receivable	302,188	498,756	(269,250)
Inventories	32,043	32,409	66,783
Accounts payable	193,012	49,702	(110,033)
Accrued taxes	36,014	(162,374)	132,892
Other working capital	(6,234)	8,304	5,821
Other—net	156,773	50,423	191,285
Net cash provided by operating activities	2,610,876	3,336,717	2,947,687
Cash Flows From Investing Activities			
Capital expenditures	(1,230,331)	(944,618)	(1,126,904)
Diversified operations	(99,532)	(178,874)	(308,810)
Acquisition of PGT Queensland Gas Pipeline	(136,227)	—	—
Acquisition of Energy Source	(23,270)	—	—
Proceeds from sale of DALEN	—	340,000	—
Other—net	(119,923)	(122,913)	(29,914)
Net cash used by investing activities	(1,609,283)	(906,405)	(1,465,628)
Cash Flows From Financing Activities			
Common stock issued	219,726	139,595	274,269
Common stock repurchased	(455,278)	(601,360)	(181,558)
Preferred stock issued	—	—	62,312
Preferred stock redeemed or repurchased	—	(358,212)	(82,875)
Company obligated mandatorily redeemable preferred securities issued	—	300,000	—
Long-term debt issued	1,087,732	591,160	60,907
Long-term debt matured, redeemed, or repurchased	(1,471,390)	(1,296,549)	(436,673)
Short-term debt issued (redeemed)—net	(115,243)	305,262	(239,478)
Dividends paid	(843,997)	(891,270)	(891,850)
Other—net	(14,036)	(21,543)	28,721
Net cash used by financing activities	(1,592,486)	(1,832,917)	(1,406,225)
Net Change in Cash and Cash Equivalents	(590,893)	597,395	75,834
Cash and Cash Equivalents at January 1	734,295	136,900	61,066
Cash and Cash Equivalents at December 31	$ 143,402	$ 734,295	$ 136,900
Supplemental disclosures of cash flow information			
Cash paid for			
Interest (net of amounts capitalized)	$ 598,394	$ 644,978	$ 674,758
Income taxes	639,813	1,125,635	712,777

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

Consolidated Balance Sheet

December 31, (in thousands)	1996	1995
Assets		
Plant in Service		
Electric		
Nonnuclear	$18,099,342	$17,530,446
Diablo Canyon	6,658,137	6,646,853
Gas	8,138,106	7,732,681
Total plant in service (at original cost)	32,895,585	31,909,980
Accumulated depreciation and decommissioning	(14,301,934)	(13,311,500)
Net plant in service	18,593,651	18,598,480
Construction Work in Progress	414,229	333,263
Other Noncurrent Assets		
Nuclear decommissioning funds	882,929	769,829
Investment in nonregulated projects	817,259	855,962
Other assets	134,271	130,128
Total other noncurrent assets	1,834,459	1,755,919
Current Assets		
Cash and cash equivalents	143,402	734,295
Accounts receivable, net	1,499,674	1,268,936
Regulatory balancing accounts receivable	444,156	746,344
Inventories		
Materials and supplies	185,771	181,763
Gas stored underground	130,229	146,499
Fuel oil	23,433	40,756
Nuclear fuel	190,652	175,957
Prepayments	54,116	47,025
Total current assets	2,671,433	3,341,575
Deferred Charges		
Income tax-related deferred charges	1,133,043	1,079,673
Other deferred charges	1,483,110	1,741,380
Total deferred charges	2,616,153	2,821,053
Total Assets	$26,129,925	$26,850,290

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

Consolidated Balance Sheet

December 31, (in thousands)	1996	1995
Capitalization and Liabilities		
Capitalization		
Common stock equity	$ 8,363,301	$ 8,599,133
Preferred stock without mandatory redemption provisions	402,056	402,056
Preferred stock with mandatory redemption provisions	137,500	137,500
Company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures	300,000	300,000
Long-term debt	7,770,067	8,048,546
Total capitalization	16,972,924	17,487,235
Current Liabilities		
Short-term borrowings	680,900	829,947
Current portion of long-term debt	209,867	304,204
Accounts payable		
Trade creditors	834,143	413,972
Other	365,499	387,747
Accrued taxes	310,271	274,093
Amounts due customers	186,899	49,175
Deferred income taxes	157,064	227,782
Interest payable	63,193	70,179
Dividends payable	123,310	205,467
Other	309,104	455,798
Total current liabilities	3,240,250	3,218,364
Deferred Credits and Other Noncurrent Liabilities		
Deferred income taxes	3,941,435	3,933,765
Deferred tax credits	379,563	393,255
Noncurrent balancing account liabilities	120,858	185,647
Other	1,474,895	1,632,024
Total deferred credits and other noncurrent liabilities	5,916,751	6,144,691
Commitments and Contingencies (Notes 1, 2, 3, 12, and 13)	—	—
Total Capitalization and Liabilities	$26,129,925	$26,850,290

Statement of Consolidated Common Stock Equity, Preferred Stock, and Preferred Securities

(dollars in thousands)	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Total Common Stock Equity	Preferred Stock Without Mandatory Redemption Provisions	Preferred Stock With Mandatory Redemption Provisions
Balance December 31, 1993	$2,136,095	$3,666,455	$2,643,487	$8,446,037	$ 807,995	$ 75,000
Net income			1,007,450	1,007,450		
Common stock issued						
(10,508,483 shares)	52,543	221,726		274,269		
Common stock repurchased						
(7,485,001 shares)	(37,425)	(66,334)	(77,799)	(181,558)		
Preferred stock issued						
(2,500,000 shares)		(188)		(188)		62,500
Preferred stock redeemed						
(3,000,000 shares)		(5,331)	(2,544)	(7,875)	(75,000)	
Cash dividends declared						
Preferred stock			(58,203)	(58,203)		
Common stock			(840,627)	(840,627)		
Other		(9,820)	5,540	(4,280)		
Balance December 31, 1994	2,151,213	3,806,508	2,677,304	8,635,025	732,995	137,500
Net income			1,338,885	1,338,885		
Common stock issued						
(5,316,876 shares)	26,584	113,011		139,595		
Common stock repurchased						
(21,533,977 shares)	(107,669)	(195,383)	(298,308)	(601,360)		
Preferred securities issued[1]						
(12,000,000 shares)						300,000
Preferred stock redeemed or						
repurchased (13,237,554 shares)		(7,814)	(19,459)	(27,273)	(330,939)	
Cash dividends declared						
Preferred stock			(56,006)	(56,006)		
Common stock			(829,828)	(829,828)		
Other			95	95		
Balance December 31, 1995	2,070,128	3,716,322	2,812,683	8,599,133	402,056	437,500
Net income			755,209	755,209		
Common stock issued						
(9,290,102 shares)	46,448	173,278		219,726		
Common stock repurchased						
(19,811,396 shares)	(99,055)	(182,088)	(174,135)	(455,278)		
Cash dividends declared						
Preferred stock			(33,113)	(33,113)		
Common stock			(728,727)	(728,727)		
Other		2,381	3,970	6,351		
Balance December 31, 1996	$2,017,521	$3,709,893	$2,635,887	$8,363,301	$ 402,056	$437,500

[1] Relates to company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures.

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

Statement of Consolidated Capitalization

December 31, (dollars in thousands, except per share amounts)	1996	1995
Common Stock Equity		
Common stock, par value $5 per share (authorized 800,000,000 shares, issued and outstanding 403,504,292 and 414,025,856)	$ 2,017,521	$ 2,070,128
Additional paid-in capital	3,709,893	3,716,322
Reinvested earnings	2,635,887	2,812,683
Common stock equity	8,363,301	8,599,133
Preferred Stock and Preferred Securities		
Preferred stock without mandatory redemption provisions		
Par value $25 per share[1]		
Nonredeemable		
5% to 6%—5,784,825 shares outstanding	144,621	144,621
Redeemable		
4.36% to 7.44%—10,297,404 shares outstanding	257,435	257,435
Total preferred stock without mandatory redemption provisions	402,056	402,056
Preferred stock with mandatory redemption provisions		
Par value $25 per share[1]		
6.30% and 6.57%—5,500,000 shares outstanding, due 2002–2009	137,500	137,500
Preferred stock	539,556	539,556
Company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures		
7.90%—12,000,000 shares outstanding, due 2025	300,000	300,000
Long-Term Debt		
PG&E long-term debt		
First and refunding mortgage bonds		
Maturity — Interest rates		
1996–2001 — 4.50% to 8.75%	880,450	915,249
2002–2006 — 5.875% to 7.875%	1,392,135	1,450,000
2007–2012 — 6.25% to 8.875%	475,000	477,870
2013–2019 — 7.5% to 8.2%	45,000	105,000
2020–2026 — 5.85% to 8.875%	2,627,736	2,749,651
Principal amounts outstanding	5,420,321	5,697,770
Unamortized discount net of premium	(49,923)	(55,802)
Total mortgage bonds	5,370,398	5,641,968
Debentures, 12%, due 2000	57,539	57,539
Pollution control loan agreements, variable rates, due 2016–2026	987,870	925,000
Unsecured medium-term notes, 4.93% to 9.9%, due 1997–2014	828,900	1,096,400
Unamortized discount related to unsecured medium-term notes	(1,187)	(1,652)
Other long-term debt	32,800	20,298
Total PG&E long-term debt	7,276,320	7,739,553
Long-term debt of PGT and Enterprises	703,614	613,197
Total long-term debt	7,979,934	8,352,750
Less current portion	209,867	304,204
Long-term debt, excluding current portion	7,770,067	8,048,546
Total Capitalization	$16,972,924	$17,487,235

[1] Authorized 75,000,000 shares in total (both with and without mandatory redemption provisions).

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

Statement of Consolidated Segment Information

(In thousands)	Electric Utility	Gas Utility	Diversified Operations[4]	Intersegment Eliminations	Total
1996					
Operating revenues	$ 7,160,215	$2,039,802	$ 409,955	$ —	$ 9,609,972
Intersegment revenues[1]	12,156	69,645	—	(81,801)	—
Total operating revenues	$ 7,172,371	$2,109,447	$ 409,955	$(81,801)	$ 9,609,972
Depreciation and decommissioning	$ 919,958	$ 288,994	$ 13,000	$ —	$ 1,221,952
Operating income before income taxes[2]	1,757,611	184,506	(47,921)	1,389	1,895,585
Capital expenditures[3]	921,425	459,074	23,270	—	1,403,769
Identifiable assets[3]	$18,005,105	$6,215,028	$1,434,216	$ —	$25,654,349
Corporate assets					475,576
Total assets at year end					$26,129,925
1995					
Operating revenues	$ 7,386,307	$2,059,117	$ 176,341	$ —	$ 9,621,765
Intersegment revenues[1]	12,678	85,356	—	(98,034)	—
Total operating revenues	$ 7,398,985	$2,144,473	$ 176,341	$(98,034)	$ 9,621,765
Depreciation and decommissioning	$ 1,007,467	$ 306,717	$ 45,934	$ —	$ 1,360,118
Operating income before income taxes[2]	2,267,193	540,378	(46,618)	2,032	2,762,985
Capital expenditures[3]	679,866	282,724	2,067	—	964,657
Identifiable assets[3]	$18,610,610	$6,064,596	$1,042,764	$ —	$25,717,970
Corporate assets					1,132,320
Total assets at year end					$26,850,290
1994					
Operating revenues	$ 8,021,547	$2,081,062	$ 247,621	$ —	$10,350,230
Intersegment revenues[1]	12,852	85,341	—	(98,193)	—
Total operating revenues	$ 8,034,399	$2,166,403	$ 247,621	$(98,193)	$10,350,230
Depreciation and decommissioning	$ 982,859	$ 295,979	$ 118,632	$ —	$ 1,397,470
Operating income before income taxes[2]	2,187,569	271,537	(32,093)	(3,227)	2,423,786
Capital expenditures[3]	834,494	292,000	19,456	—	1,145,950
Identifiable assets[3]	$19,637,222	$6,167,314	$1,436,128	$ —	$27,240,664
Corporate assets					467,900
Total assets at year end					$27,708,564

[1] Intersegment electric and gas revenues are accounted for at tariff rates prescribed by the CPUC.
[2] General corporate expenses are allocated in accordance with FERC Uniform System of Accounts and requirements of the CPUC.
[3] Includes an allocation of common plant in service and allowance for funds used during construction.
[4] Represents the nonregulated operations of wholly-owned subsidiaries including Enterprises, Mission Trail Insurance Ltd. (liability insurance), and Energy Source (gas marketing).

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

Note 1: Significant Accounting Policies

Corporate Restructuring: Effective January 1, 1997, Pacific Gas and Electric Company (PG&E) became a subsidiary of its new parent holding company, PG&E Corporation. PG&E's ownership interest in Pacific Gas Transmission Company (PGT) and PG&E Enterprises (Enterprises) was transferred to PG&E Corporation. PG&E's outstanding common stock was converted on a share-for-share basis into PG&E Corporation's outstanding common stock. PG&E's debt securities and preferred stock were unaffected and remain securities of PG&E. The members of PG&E's current Board of Directors became directors of PG&E Corporation.

Basis of Presentation: The consolidated financial statements include the accounts of PG&E and its wholly-owned and controlled subsidiaries (collectively, the Company) and, therefore, also represent the accounts of PG&E Corporation and its subsidiaries. All significant intercompany transactions have been eliminated. Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the 1996 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 disclosure of contingencies. Actual results could differ from these estimates.

Operations: The Company and its subsidiaries provide electric and natural gas services and retail energy services. PG&E is a regulated public utility which provides generation, procurement, transmission, and distribution of electricity and natural gas throughout most of Northern and Central California. PGT transports gas from the Canadian border to the California border and the Pacific Northwest. PGT also has operations in Australia and Texas. Enterprises, through its subsidiaries and affiliates, develops, owns, and operates electric and gas projects and provides energy services.

Regulation: PG&E is regulated by the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC), and the Nuclear Regulatory Commission, among others. PG&E currently accounts for the economic 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 the Company to record certain regulatory assets and liabilities which would be included in future rates and would not be recorded under generally accepted accounting principles for nonregulated entities.

Effective January 1, 1996, the Company adopted SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 121 prescribes general standards for the recognition and measurement of impairment losses. In addition, it requires that regulatory assets continue to be probable of recovery in rates, rather than only at the time the regulatory asset is recorded. Regulatory assets currently recorded would be written off if recovery is no longer probable. Adoption of this standard had no material impact on the Company's financial position or results of operations.

On an ongoing basis, PG&E reviews its regulatory assets and liabilities for the continued applicability of SFAS No. 71 and the effect of SFAS No. 121. (See Note 2 for further discussion.)

Net regulatory assets and liabilities include the following:

December 31, (in millions)	1996	1995
Deferred income tax	$1,133	$1,080
Unamortized loss net of gain on reacquired debt	377	392
Diablo Canyon pre-settlement costs	364	382
Workers' compensation and disability claims costs	288	297
Regulatory balancing accounts (net)	323	561
Other deferred (net)	267	474
	$2,752	$3,186

Revenues and Regulatory Balancing Accounts: Revenues are recorded primarily for delivery of gas and electric energy to customers. Electric and gas utility revenues include amounts for services rendered but unbilled at the end of the year. Revenues also are recorded for changes in regulatory balancing accounts established by the CPUC. Specifically, sales balancing accounts accumulate differences between authorized and actual base revenues. Energy cost balancing accounts accumulate differences between the actual cost of gas and electric energy and the revenues designated for recovery of such costs. Recovery of gas and electric energy costs through energy cost balancing accounts is subject to reasonableness reviews by the CPUC. The regulatory balancing accounts accumulate balances until they are refunded to or received from utility customers through authorized rate adjustments.

Dividend Restriction: PG&E is limited as to the amount of dividends that it may pay to PG&E Corporation based on PG&E's regulatory capital structure authorized by the CPUC. PG&E's equity shall be retained such that, on average, the capital structure authorized by the CPUC is maintained. This restriction is not expected to affect PG&E Corporation's ability to meet its cash obligations.

Financial Derivative Instruments (Derivatives): The Company engages in price risk management activities to manage risks associated with changes in energy commodity prices, interest rates, and foreign currencies. These price risk management activities include the use of derivatives.

Gains and losses on derivatives used for hedging purposes are intended to offset losses and gains on the underlying hedged item. Under hedge accounting, changes in the market value of these transactions are deferred and recognized as an addition to the income or expense of the underlying instrument upon completion of the underlying transaction. All 1996 transactions were accounted for using hedge accounting. Gains and losses associated with derivative transactions during 1996 were immaterial.

Plant in Service: The cost of plant additions and replacements includes labor, materials, construction overhead, and an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions. Capitalized interest is the interest incurred on borrowed funds used to finance nonregulated plant additions. The original cost of retired plant and removal costs less salvage value is charged to accumulated depreciation upon retirement of plant in service.

Plant in service is depreciated using a straight-line remaining-life method. The Company's composite depreciation rates were 3.65, 4.09, and 4.31 percent for the years ended December 31, 1996, 1995, and 1994.

Nuclear Decommissioning Costs: The estimated total obligation for decommissioning PG&E's nuclear power facilities is comprised of the total cost (including labor, materials, and other costs) of decommissioning and dismantling plant systems and structures. In addition, a contingency amount for possible changes in regulatory requirements and increases in waste disposal costs is included in the estimated total obligation.

The estimated total obligation for nuclear decommissioning costs, based on a 1994 site study, is approximately $1.2 billion in 1996 dollars (or $5.9 billion in future dollars). 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 of each facility.

For the years ended December 31, 1996, 1995, and 1994, nuclear decommissioning costs recovered in rates through an annual allowance were $33, $54, and $54 million, respectively. Based on the 1994 site study, the amount assumed to be recovered in rates in 1997 and annually up to the commencement of decommissioning is $33 million. This amount will be reviewed in future rate proceedings.

At December 31, 1996, the total nuclear decommissioning obligation accrued was $889 million and was 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. (See Note 8 for further discussion of nuclear decommissioning funds.)

Decommissioning is scheduled to begin for Diablo Canyon Nuclear Power Plant's (Diablo Canyon) Unit 1 and Unit 2 in 2015 and 2016, respectively, with scheduled completion for both units in 2034. The decommissioning method selected for Diablo Canyon anticipates that the facilities will be decontaminated to a level that permits the property to be released for unrestricted use.

Decommissioning for Humboldt Bay Power Plant is scheduled to begin in 2015. The decommissioning method selected consists of placing and maintaining the facility in protective storage until some future time when dismantling can be initiated.

PG&E, as required by federal law, has signed a contract with the U.S. Department of Energy (DOE) to provide for the disposal of spent nuclear fuel and high-level radioactive waste from PG&E's nuclear power facilities beginning not later than January 1998. However, due to delays in identifying a storage site, the DOE has officially acknowledged that it will not be able to meet its contract commitment. 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, PG&E'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. PG&E is examining options for providing additional temporary spent fuel storage at Diablo Canyon or other facilities, pending disposal or storage at a DOE facility.

Gains and Losses on Reacquired Debt: Gains and losses on reacquired debt charged to operations 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 other operations are recognized in earnings at the time such debt is reacquired.

Inventories: 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. Other inventories are valued at average cost except for fuel oil, which is valued by the last-in-first-out method.

Cash Equivalents: Cash equivalents (stated at cost, which approximates market) include working funds and short-term investments with original maturities of three months or less.

Note 2: Electric Industry Restructuring

In 1995, the CPUC issued a decision that provides a plan to restructure California's electric utility industry. The decision acknowledges that much of utilities' current costs and commitments result from past CPUC decisions and that, in a competitive generation market, utilities would not recover some of these costs through market-based revenues. To assure the continued financial integrity of California utilities, the CPUC authorized recovery of these above-market costs, called "transition costs."

In 1996, California legislation was passed that adopts the basic tenets of the CPUC's restructuring decision, including recovery of transition costs. In addition, the legislation provides a 10 percent rate reduction for residential and small commercial customers by January 1, 1998, freezes electric customer rates for all other customers, and requires the accelerated recovery of transition costs associated with owned generation facilities. The legislation also establishes the operating framework for a competitive generation market.

The rate freeze will continue until the earlier of March 31, 2002, or until PG&E has recovered its transition costs (the transition period). The freeze will hold rates at 1996 levels for all customers except those receiving the 10 percent rate reduction. The rate freeze will hold the rates for these customers at the reduced level.

To achieve the 10 percent rate reduction, the legislation authorizes utilities to finance a portion of their transition costs with "rate reduction bonds." The maturity period of the bonds is expected to extend beyond the transition period. Also, the interest cost of the bonds is expected to be lower than PG&E's current cost of capital. Once this portion of transition costs is financed, PG&E would collect a bond service payment to recover principal, interest, and issuance costs over the life of the bonds from residential and small commercial customers. The combination of the longer maturity period and the reduced interest costs will lower the amounts paid by these customers each year during the transition period thereby achieving the 10 percent reduction in rates.

Tax-exempt trusts have been established to oversee the development of the operating framework for the competitive generation market. The CPUC has authorized California utilities to guarantee bank loans of up to $250 million to be used by the trusts for this purpose. Under this authorization, PG&E will guarantee a maximum of $112.5 million of these loans.

Transition Cost Recovery: The legislation authorizes the CPUC to determine the costs eligible for recovery as transition costs. The amount of costs will be based on the aggregate of above-market and below-market values of utility-owned generation assets and obligations. PG&E has proposed that costs eligible for transition cost recovery include: (1) above-market sunk costs (costs associated with utility generating facilities that are fixed and unavoidable and currently collected through rates) and future costs, such as costs related to plant removal,

(2) above-market costs associated with purchase power obligations with Qualifying Facilities (QFs) and other Power Purchase Agreements, and (3) generation-related regulatory assets and obligations. PG&E cannot determine the exact amount of sunk costs that will be above market and recoverable as transition costs until a market valuation process (appraisal or sale) is completed for each generation facility. This process will be completed during the transition period.

Most transition costs must be recovered by March 1, 2002. However, the legislation authorizes recovery of certain transition costs after that time. These costs include: (1) certain employee-related transition costs, (2) payments under existing QF and power purchase contracts, and (3) unrecovered implementation costs. Excluding these exceptions, any transition costs not recovered during the transition period will be absorbed by PG&E. Nuclear decommissioning costs, which are not considered transition costs, will be recovered through a CPUC authorized charge. During the transition period, this charge will be incorporated into the frozen rates. After the transition period, customers will be assessed a surcharge until the nuclear decommissioning costs are fully recovered.

PG&E's ability to recover its transition costs during the transition period will be dependent on several factors. These factors include: (1) the extent to which application of the current regulatory framework established by the restructuring legislation will continue to be applied, (2) the amount of transition costs approved by the CPUC, (3) the market value of its generation plants, (4) future sales levels, (5) fuel and operating costs, (6) the market price of electricity, and (7) the ratemaking methodology adopted for Diablo Canyon. Considering its current evaluation of these factors, PG&E believes it will recover its transition costs and that its owned generation plants are not impaired. However, a change in these factors could affect the probability of recovery of transition costs and result in a material loss.

PG&E has proposed to implement portions of its transition cost recovery plan in 1997. The CPUC decision on PG&E's 1997 Energy Cost Adjustment Clause (ECAC) application would decrease PG&E's 1997 revenue requirement by $720 million. This decrease would be partially offset by a $160 million revenue requirement increase, provided by the legislation, for purposes of enhancing transmission and distribution system safety and reliability. This increase was approved by the CPUC as part of PG&E's transition cost recovery plan.

Given the electric customer rate freeze, the $560 million net revenue requirement decrease resulting from the consolidation of the ECAC decision and the revenue requirement increase contemplated in the cost recovery plan would be available for transition cost recovery. The proposed accelerated recovery of Diablo Canyon would absorb an estimated $400 million of this available revenue requirement. The remaining revenue requirement would be available to recover other transition costs.

Accounting for the Effects of Regulation: As a result of applying the provisions of SFAS No. 71 (discussed in Note 1 above), PG&E has accumulated approximately $1.6 billion of regulatory assets attributable to electric generation at December 31, 1996. The net investments in Diablo Canyon and the other generation assets were $4.5 and $2.7 billion, respectively, at December 31, 1996. The net present value of above-market QF power purchase obligations is estimated to be $5.3 billion at January 1, 1998, at an assumed market price of $0.025 per kilowatt-hour (kWh) beginning in 1997 and escalating at 3.2 percent per year.

PG&E believes that the restructuring legislation establishes a definitive transition to market-based pricing for electric generation. Incorporating the effects of the competitive auction pricing of electricity and customer direct access, this transition includes cost-of-service based ratemaking. In addition, PG&E's generation-related transition costs will be collected through a nonbypassable charge. Based on this structure, PG&E believes it will continue to meet the requirements of SFAS No. 71 throughout the transition period.

At the conclusion of the transition period, PG&E believes it will be at risk to recover its generation costs through market-based revenues. At that time, PG&E expects to discontinue the application of SFAS No. 71 for the electric generation portion of its business. Since PG&E anticipates it will have recovered all transition costs required to be recovered during the transition period, including generation-related regulatory assets and above-market investments in net plant, PG&E does not expect a material adverse impact on its financial position or results of operations from discontinuing the application at that time.

As a result of the CPUC's restructuring decision and California's electric industry restructuring legislation, the Securities and Exchange Commission (SEC) has begun inquiries regarding the appropriateness of the continued application of

SFAS No. 71 by California utilities to their electric generation businesses. As discussed above, PG&E believes it currently meets and will continue to meet the requirements to apply SFAS No. 71 during the transition period. In the event that the SEC concludes that the current regulatory and legal framework in California no longer meets the requirements to apply SFAS No. 71 to the generation business, the Company would reevaluate the financial impact of electric industry restructuring and a material write-off could occur.

Given the current regulatory environment, PG&E's electric transmission and distribution businesses are expected to remain regulated and, as a result, will continue application of the provisions of SFAS No. 71.

Note 3: Natural Gas Matters

The Gas Accord Settlement (Accord): In an effort to promote competition and to give all residential and smaller commercial (core) customers the same options that exist for industrial and larger commercial (noncore) customers, PG&E submitted the Accord to the CPUC in 1996. In addition to offering increased customer choice, the Accord would establish gas transmission rates for the period July 1997 through December 2002 and resolve various pending regulatory issues. The Accord must be approved by the CPUC before it can be implemented. A CPUC decision is expected in 1997.

The major outstanding gas regulatory issues that the Accord would resolve include the 1988 through 1995 gas reasonableness proceedings, the initial capital costs for the PG&E Pipeline Expansion, the interstate transition cost surcharge (ITCS) recovery, and the PG&E pipeline transportation commitments, all of which are discussed in further detail below.

As of December 31, 1996, PG&E has reserved approximately $527 million, including $182 million reserved during 1996, relating to its gas regulatory issues and gas capacity commitments, the majority of which are addressed by the Accord. The Company believes the ultimate resolution of these matters, whether through approval of the Accord or otherwise, will not have a material adverse impact on its financial position or future results of operations.

Gas Reasonableness Proceedings: Recovery of gas costs through PG&E's regulatory balancing account mechanisms is subject to a CPUC determination that such costs were reasonable. Under the current regulatory framework, annual reasonableness proceedings are conducted by the CPUC on a historic calendar year basis.

In 1994, the CPUC issued a decision which ordered a disallowance of approximately $90 million of gas costs plus accrued interest of approximately $25 million through 1993 for PG&E's Canadian gas procurement activities from 1988 through 1990. PG&E has filed a lawsuit in a federal district court challenging the CPUC's decision on Canadian gas costs. PG&E expects this issue to be resolved as part of the Accord discussed above. Under the Accord, PG&E would agree to forgo recovery of the $90 million disallowance ordered in the 1988 through 1990 gas reasonableness proceeding, irrespective of the outcome of the lawsuit.

A number of other reasonableness issues related to PG&E's gas procurement practices, transportation capacity commitments, and supply operations for periods dating from 1988 to 1994 were resolved when the CPUC accepted a settlement in December 1996 between PG&E and the Office of Ratepayer Advocates (ORA) of the CPUC. Under the terms of that settlement, PG&E will return $67 million plus interest to ratepayers in 1997. PG&E has previously recorded reserves for this settlement.

PGT/PG&E Pipeline Expansion: In November 1993, the Company expanded its natural gas transmission system providing additional firm transportation capacity from the Canadian border to Northern and Southern California and the Pacific Northwest.

PG&E has filed an application with the CPUC requesting that capital costs of $810 million and ongoing operating costs for the PG&E, or California, portion of the Pipeline Expansion be found reasonable. Revenues are currently being collected under interim rates approved by the CPUC, subject to adjustment.

In 1996, a CPUC Administrative Law Judge (ALJ) ordered consolidation of the market impact phase of the PG&E Pipeline Expansion reasonableness proceeding and the ITCS proceeding discussed below. An ALJ also ordered reopening of the 1993 PG&E Pipeline Expansion Rate Case to allow reconsideration of issues regarding the decision to construct the PG&E Pipeline Expansion. Were the CPUC to reverse its previous decision, which found that PG&E was reasonable in constructing the PG&E Pipeline Expansion, the ultimate outcome could have an adverse impact on PG&E's ability to recover its cost for unused capacity on other pipelines as well as on its own intrastate facilities. PG&E expects these issues to be resolved as part of the Accord discussed above. Under the Accord, PG&E would agree to set rates for the PG&E Pipeline Expansion based on total capital costs of $736 million.

Transportation Commitments: PG&E 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 PG&E will pay each year may change due to changes in tariff rates. The total demand and transportation charges paid by PG&E under these agreements (excluding agreements with PGT) were approximately $212, $175, and $225 million in 1996, 1995, and 1994, respectively.

The following table summarizes the approximate capacity held by PG&E on various pipelines (excluding PGT) and the related annual demand charges at December 31, 1996:

Pipeline Company	Firm Capacity Held (MMcf/d)	Total Annual Gross Demand Charges (in millions)	Contract Expiration
El Paso	1,140	$163	Dec. 1997
Transwestern	200	$ 29	Mar. 2007
NOVA	600	$ 20	Oct. 2001
ANG	600	$ 13	Oct. 2005

As a result of regulatory changes, PG&E no longer procures gas for its noncore customers, resulting in a decrease in PG&E's need for firm transportation capacity for its gas purchases. PG&E continues to procure gas for almost all of its core customers and those noncore customers who choose bundled service (core subscription customers). To serve these customers, PG&E holds approximately 600 million cubic feet per day (MMcf/d) of firm capacity for its core and core subscription customers on each of the pipelines owned by El Paso Natural Gas Company (El Paso), NOVA Corporation of Alberta (NOVA), Alberta Natural Gas Company Ltd (ANG), and PGT.

PG&E is continuing its efforts to broker or assign any remaining unused capacity, including unused capacity held for its core and core subscription customers. Due to relatively low demand for Southwest pipeline capacity, PG&E cannot predict the volume or price of the capacity on El Paso and Transwestern Pipeline Company (Transwestern) that will be brokered or assigned.

Substantially all demand charges incurred by PG&E for pipeline capacity are eligible for rate recovery, subject to a reasonableness review. These demand charges include capacity that was formerly used to serve noncore customers but which at present cannot be brokered or which is brokered at a discount. However, certain groups, including the ORA and intervenors, have challenged the recovery of these unrecovered demand charges.

In December 1995, the CPUC issued a decision on the reasonableness of PG&E's 1992 operations, concluding that it was unreasonable for PG&E to commit to transportation capacity with Transwestern. The decision orders that costs for the capacity in subsequent years of the contract, which expires in 2007, be disallowed unless PG&E can demonstrate that the benefits of the commitment outweigh the costs.

The recovery of demand charges associated with capacity which was formerly used to serve PG&E's noncore customers will be decided by the CPUC in the ITCS proceeding, unless otherwise resolved as part of the Accord. Pending a final decision in the ITCS proceeding, the CPUC has approved collection (subject to refund) in rates of approximately 50 percent of the demand charges for unbrokered or discounted El Paso and PGT capacity which was formerly used to serve PG&E's noncore customers.

Under the Accord, PG&E would not recover costs through 1997 associated with Transwestern capacity originally subscribed to in order to serve core customers and would have limited recovery during the period 1998 through 2002. Also as part of the Accord, PG&E would forgo recovery of 100 percent and 50 percent of the ITCS amounts allocated to its core and noncore customers, respectively.

The Company believes ultimate resolution of its capacity commitments and the ITCS proceeding, either through approval of the Accord or otherwise, will not have a material adverse impact on its financial position or future results of operations.

Note 4: Diablo Canyon

The Diablo Canyon rate case settlement as adopted in 1988 and modified in 1995 (Diablo Settlement) bases revenues primarily on the amount of electricity generated by Diablo Canyon. The Diablo Settlement provides that Diablo Canyon costs and operations are not subject to CPUC reasonableness reviews. Only certain Diablo Canyon costs may be recovered through base revenues over the term of the Diablo Settlement, including a full return on such costs. The revenues to recover all Diablo Canyon costs are included in Diablo Canyon operating revenues reported below. Other than for these and decommissioning costs, Diablo Canyon discontinued the application of SFAS No. 71 in July 1988.

Under the pricing provisions of the existing Diablo Settlement, the price for power produced by Diablo Canyon for 1997 is 10.0 cents per kWh effective January 1. PG&E has the right to reduce the price below the amount specified. Under the existing settlement, at full operating power, each Diablo Canyon unit would contribute approximately $2.6 million in revenues per day in 1997. The prices per kWh of electricity generated by Diablo Canyon for 1996, 1995, and 1994 were 10.50, 11.00, and 11.89 cents per kWh, respectively.

Selected financial information for Diablo Canyon is shown below:

Year ended December 31, (in millions)	1996	1995	1994
Operating revenues	$1,789	$1,845	$1,870
Operating income before income taxes	998	1,029	956
Net income	497	507	461

In determining operating results of Diablo Canyon, operating revenues and the majority of operating expenses were specifically identified pursuant to the Diablo Settlement. Administrative and general expenses, principally labor costs, are allocated based on a study of labor costs. Interest is charged to Diablo Canyon based on an allocation of PG&E debt.

In conjunction with electric industry restructuring, PG&E filed in March 1996 a proposal for pricing Diablo Canyon generation at market prices and completing recovery of the investment in Diablo Canyon by the end of 2001. If this proposal is adopted, there would be a significant change to the manner in which Diablo Canyon earns revenues.

Under its proposal, PG&E would replace the existing settlement prices with: (1) a sunk cost revenue requirement to recover fixed costs, including a return on these costs, and (2) a performance-based ratemaking (PBR) mechanism to recover the facility's variable costs and capital addition costs. As proposed, the sunk cost revenue requirement would accelerate recovery of Diablo Canyon sunk costs from a twenty-year period ending in 2016 to a five-year period beginning in 1997 and ending in 2001. The related return on common equity associated with Diablo Canyon sunk costs would be reduced to 90 percent of PG&E's long-term cost of debt. PG&E's authorized long-term cost of debt was 7.52 percent in 1996. The reduced rate of return combined with a shorter recovery period would result in an estimated $4 billion decrease in the net present value of PG&E's future revenues from Diablo Canyon operations. If the proposed cost recovery plan for Diablo Canyon were adopted during 1996, Diablo Canyon's 1996 reported net income would have been reduced by $350 million ($0.85 per share).

Note 5: Preferred Stock and Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely PG&E Subordinated Debentures

(See the Statement of Consolidated Capitalization for additional information.)

Preferred Stock: PG&E's nonredeemable preferred stock at December 31, 1996, has rights to annual dividends per share ranging from $1.25 to $1.50.

PG&E's redeemable preferred stock without mandatory redemption provisions is subject to redemption at PG&E's option, in whole or in part, if PG&E pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share at December 31, 1996, range from $1.09 to $1.86 and from $25.75 to $27.25, respectively.

PG&E's redeemable preferred stock with mandatory redemption provisions consists of the 6.30% and 6.57% series at December 31, 1996. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding. They may be redeemed at PG&E's option, beginning in 2004 and 2002, respectively, at par value plus accumulated and unpaid dividends through the redemption date. The estimated fair value of PG&E's preferred stock with mandatory redemption provisions at December 31, 1996, and 1995, was approximately $135 and $139 million, respectively, based on quoted market prices.

In 1995, PG&E redeemed all of its series 7.84%, 8%, and 8.20% redeemable preferred stock. In addition, PG&E repurchased partial amounts of its series 6⅞%, 7.04%, and 7.44% redeemable preferred stock through a tender offer. The aggregate par value of these redemptions and repurchases was $331 million.

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 PG&E, 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.

Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely PG&E Subordinated Debentures: During 1995, PG&E through its wholly-owned subsidiary, PG&E Capital I (Trust), completed a public offering of 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 PG&E 371,135 shares of common securities with an aggregate liquidation value of approximately $9 million. The Trust in turn used the net proceeds from the QUIPS offering and issuance of the common securities to purchase subordinated debentures issued by PG&E with a face value of approximately $309 million, an interest rate of 7.90 percent, and a maturity date of 2025. These subordinated debentures are the only assets of the Trust. Proceeds to PG&E from the sale of the subordinated debentures were used to redeem and repurchase higher-cost preferred stock.

PG&E's guarantee of the QUIPS, considered together with the other obligations of PG&E with respect to the QUIPS, constitutes a full and unconditional guarantee by PG&E of the Trust's obligations under the QUIPS issued by the Trust. The subordinated debentures may be redeemed at PG&E's option beginning in 2000 at par 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 PG&E, 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. The estimated fair value of PG&E's QUIPS at December 31, 1996, and 1995, was approximately $291 and $311 million, respectively, based on quoted market prices.

Note 6: Long-term Debt

(See the Statement of Consolidated Capitalization for additional information.)

Mortgage Bonds: PG&E had $5.4 and $5.7 billion of mortgage bonds outstanding at December 31, 1996, and 1995, respectively. Additional mortgage bonds may be issued, subject to CPUC approval, up to a maximum total amount outstanding of $10 billion. All real properties and substantially all personal properties of PG&E are subject to the lien of the mortgage, and PG&E is required to make semi-annual sinking fund payments for the retirement of the bonds.

PG&E redeemed or repurchased $182 and $114 million of mortgage bonds in 1996 and 1995, respectively, with interest rates ranging from 5.375 to 12.75 percent.

Included in the total of outstanding mortgage bonds at December 31, 1996, and 1995, are $705 and $768 million, respectively, of mortgage bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 to 8.875 percent and maturity dates from 2007 to 2023. In addition to these mortgage bonds, PG&E holds long-term loan agreements with the CPCFA as described below.

Pollution Control Loan Agreements: In 1996, PG&E refinanced $925 million of variable interest rate pollution control loan agreements with variable interest rate pollution control loan agreements to extend certain maturities and achieve cost savings. These loan agreements from the CPCFA totaled $988 and $925 million, respectively, at December 31, 1996, and 1995. Interest rates on the loans vary with average annual interest rates for 1996 ranging from 3.24 to 3.54 percent. These loans are subject to redemption by the holder under certain circumstances. These loans are secured by irrevocable letters of credit which mature as early as 1999.

Long-term Debt of PGT: In 1996, PGT borrowed $92 million of long-term debt to finance the acquisition of PGT Queensland Gas Pipeline.

In 1995, PGT issued $470 million of long-term debt, the proceeds of which were used to refinance $600 million of outstanding PGT debt.

Additionally, in 1995, PGT issued commercial paper classified as long-term debt based upon the availability of committed credit facilities expiring in 2000 and management's intent to maintain such amounts in excess of one year. The commercial paper outstanding was $108 and $109 million at December 31, 1996, and 1995, respectively.

Repayment Schedule: At December 31, 1996, the Company's combined aggregate amounts of maturing long-term debt and sinking fund requirements, for the years 1997 through 2001, are $210, $660, $270, $413, and $376 million, respectively.

Fair Value: The estimated fair value of the Company's total long-term debt of $8.0 and $8.4 billion at December 31, 1996, and 1995, respectively, was approximately $8.0 and $8.7 billion, respectively. The estimated fair value of long-term debt was determined based on quoted market prices, where available. Where quoted market prices were not available, the estimated fair value was determined using other valuation techniques (e.g., the present value of future cash flows).

Note 7: Short-term Borrowings

Substantially all short-term borrowings consist of commercial paper, having a maturity of one to ninety days. Commercial paper outstanding and the associated weighted average interest rate at December 31, 1996, and 1995, were $681 million and 5.86 percent and were $796 million and 5.92 percent, respectively. The carrying amount of short-term borrowings approximates fair value.

PG&E maintains a $1 billion revolving credit facility which expires in 2001; however, it may be extended annually for additional one-year periods upon mutual agreement between PG&E and the banks. This credit facility primarily provides support for PG&E's commercial paper issuance. At maturity, commercial paper can be either reissued or replaced with borrowings from this credit facility. There were no borrowings under this facility in 1996 or 1995.

In January 1997, PG&E Corporation established a $500 million revolving credit facility in order to provide for corporate short-term liquidity needs and other purposes.

Note 8: Investments in Debt and Equity Securities

All of PG&E's investments in debt and equity securities are held in external trust funds and are reported at fair value. These investments, which are included in Nuclear Decommissioning Funds, cannot be released from the trust funds until authorized by the CPUC.

The proceeds received during 1996 and 1995 from sales were approximately $1.5 billion in each year. During 1996 and 1995, the gross realized gains on sales of securities held as available-for-sale were $14 and $9 million, respectively, and the gross realized losses on sales of securities held as available-for-sale were $20 and $22 million, respectively. The cost of debt and equity securities sold is determined by specific identification.

The following table provides a summary of amortized cost and fair value of these investments:

Year ended December 31, (in thousands)	1996	1995
Amortized Cost:		
U.S. government and agency issues	$374,931	$322,838
Equity securities	281,532	269,117
Municipal bonds and other	32,952	63,061
Gross unrealized holding gains	198,875	117,673
Gross unrealized holding losses	(5,361)	(2,860)
Fair value	$882,929	$769,829

Note 9: Employee Benefit Plans

Retirement Plan: The Company provides noncontributory defined benefit pension plans covering substantially all employees. Pension benefits are based on an employee's years of service and base salary. The Company's policy is to fund each year not more than the maximum amount deductible for federal income tax purposes and not less than the minimum legal funding requirement.

The following schedule reconciles the plans' funded status to the pension liability recorded on the Consolidated Balance Sheet:

December 31, (in thousands)	1996	1995
Actuarial present value of benefit obligations		
Vested benefits	$(3,486,136)	$(3,464,782)
Nonvested benefits	(177,782)	(182,503)
Accumulated benefit obligation	(3,663,918)	(3,647,285)
Effect of projected future compensation increases	(529,045)	(548,743)
Projected benefit obligation	(4,192,963)	(4,196,028)
Plan assets at market value	5,526,247	4,935,267
Plan assets in excess of projected benefit obligation	1,333,284	739,239
Unrecognized prior service cost	82,756	90,496
Unrecognized net gain	(1,559,281)	(1,074,347)
Unrecognized net transition obligation	85,895	97,348
Accrued pension liability	$ (57,346)	$ (147,264)

Plan assets consist primarily of common stocks and fixed-income securities. Unrecognized prior service costs and net gains are amortized on a straight-line basis over the average remaining service period of active plan participants. The transition obligation is being amortized over 17.5 years from 1987.

Using the projected unit credit actuarial cost method, net pension income consisted of the following components:

Year ended December 31, (in thousands)	1996	1995	1994
Service cost for benefits earned	$ (99,946)	$ (82,814)	$(109,132)
Interest cost	(301,631)	(290,563)	(272,932)
Actual return (loss) on plan assets	811,130	968,126	(20,358)
Net amortization and deferral	(353,195)	(586,350)	412,547
Net pension income	$ 56,358	$ 8,399	$ 10,125

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

December 31,	1996	1995	1994
Discount rate	7.5%	7.25%	8%
Rate of future compensation increases	5%	5%	5%
Expected long-term rate of return on plan assets	9%	9%	9%

Net pension income or cost is calculated using expected return on plan assets. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future net pension income or cost. In 1996 and 1995, actual return on plan assets exceeded expected return. In 1994, the plan experienced a negative investment return due to weak performance in domestic equities and bonds.

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

Postretirement Benefits Other Than Pensions: The Company provides contributory defined benefit medical plans for retired employees and their eligible dependents and noncontributory defined benefit life insurance plans for retired employees. Substantially all employees retiring at or after age 55 are eligible for these benefits. The medical benefits are provided through plans administered by an insurance carrier or a health maintenance organization. Certain retirees are responsible for a portion of the cost based on past claims experience of the Company's retirees.

The CPUC has authorized PG&E to recover these benefits for 1993 and beyond. Recovery is based on the lesser of the annual accounting costs or annual contributions on a tax-deductible basis to appropriate trusts. The Company's policy is to fund each year an amount consistent with the basis for rate recovery.

The following schedule reconciles the medical and life insurance plans' funded status to the postretirement benefit liability recorded on the Consolidated Balance Sheet:

December 31, (in thousands)	1996	1995
Accumulated postretirement benefit obligation		
Retirees	$(444,782)	$(528,367)
Other fully eligible participants	(132,797)	(123,615)
Other active plan participants	(343,864)	(309,405)
Total accumulated postretirement benefit obligation	(921,443)	(961,387)
Plan assets at market value	666,287	538,905
Accumulated postretirement benefit obligation in excess of plan assets	(255,156)	(422,482)
Unrecognized prior service cost	21,946	23,761
Unrecognized net gain	(226,753)	(104,167)
Unrecognized transition obligation	419,617	449,647
Accrued postretirement benefit liability	$ (40,346)	$ (53,241)

Plan assets consist primarily of common stocks and fixed-income securities. Unrecognized prior service costs are amortized on a straight-line basis over the average remaining years of service to full eligibility of active plan participants. Unrecognized net gains are amortized on a straight-line basis over the average remaining years of service of active plan participants. The transition obligation is being amortized over 20 years from 1993.

Using the projected unit credit actuarial cost method, net postretirement medical and life insurance cost consisted of the following components:

Year ended December 31, (in thousands)	1996	1995	1994
Service cost for benefits earned	$ 21,954	$ 17,004	$ 23,617
Interest cost	65,629	64,776	64,872
Actual return on plan assets	(91,050)	(108,932)	(1,232)
Amortization of unrecognized prior service cost	1,602	1,616	1,711
Amortization of transition obligation	26,314	26,533	28,913
Net amortization and deferral	38,329	70,070	(29,804)
Net postretirement benefit cost	$ 62,778	$ 71,067	$ 88,077

The discount rate, rate of future compensation increases, and expected long-term rate of return on plan assets used in accounting for the postretirement benefit plans for 1996, 1995, and 1994 were the same as those used for the pension plan.

The assumed health care cost trend rate for 1997 is approximately 10.0 percent, grading down to an ultimate rate in 2005 of approximately 6.0 percent. The effect of a one-percentage-point increase in the assumed health care cost trend rate for each future year would increase the accumulated postretirement benefit obligation at December 31, 1996, by approximately $75 million and the 1996 aggregate service and interest costs by approximately $8 million.

The decrease in net postretirement benefit cost in 1995 compared to 1994 was primarily due to a reduction in workforce and an increase in discount rate.

Net postretirement benefit cost is calculated using expected return on plan assets. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future postretirement benefit cost. In 1996 and 1995, actual return on plan assets exceeded expected return. In 1994, actual return on plan assets was less than expected.

Workforce Reductions: The effects of workforce reductions announced by PG&E in 1994 are reflected in the pension and postretirement benefits funded status tables above, and the costs are discussed in Note 10.

Long-term Incentive Program: PG&E Corporation maintains a Long-term Incentive Program (Program) which provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents. The Program also grants performance-based units to eligible participants. As of December 31, 1996, 24.5 million shares of common stock have been authorized for award under the program. At December 31, 1996, stock options on 3,461,733 shares, granted at option prices ranging from $16.75 to $34.25, were outstanding, of which 1,655,450 were exercisable. In 1996, 877,900 options were granted at an option price of $28.25, which was the market price per share on the date of grant.

Outstanding stock options expire ten years and one day after the date of grant and become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. In 1996, 1995, and 1994, stock options on 72,960, 235,568, and 52,143 shares, respectively, were exercised at option prices ranging from $16.75 to $33.13, $16.75 to $33.13, and $24.75 to $32.13, respectively.

Effective January 1, 1996, the Company adopted SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 requires the Company to disclose stock option costs based on the fair value of options granted. For the years ended December 31, 1996, and 1995, the fair value of options granted was not material to the Company's results of operations or earnings per share.

Note 10: Workforce Reductions

In 1994, PG&E expensed the total cost of its planned 1994-1995 workforce reductions of $249 million and recorded a corresponding liability for benefits to be funded or paid. This amount consisted of $136 million for additional pension benefits, $52 million for other postretirement benefits, and $61 million for estimated severance costs. PG&E did not seek rate recovery for the cost of the 1994-1995 workforce reductions.

In 1995, PG&E canceled approximately 800 of the 3,000 planned 1994-1995 reductions in response to the severity of the damage caused by the winter storms of 1995 and the identification of certain facilities that would benefit from a more extensive and accelerated maintenance program. As a result, the estimated severance costs accrued and expensed in 1994 were reduced by $18 million in 1995.

Note 11: Income Taxes

The Company files a consolidated federal income tax return that includes domestic subsidiaries in which its ownership is 80 percent or more. 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.

The significant components of income tax expense were:

Year ended December 31, (in thousands)	1996	1995	1994
Current	$ 704,984	$1,011,358	$821,455
Deferred	(132,250)	(97,864)	34,657
Tax credits—net	(17,740)	(18,205)	(19,345)
Total income tax expense	$ 554,994	$ 895,289	$836,767

The significant components of net deferred income tax liabilities were:

December 31, (in thousands)	1996	1995
Deferred income tax assets	$1,308,395	$1,203,981
Deferred income tax liabilities:		
Regulatory balancing accounts	$ 294,494	$ 385,604
Plant in service	3,623,544	3,552,974
Income tax-related deferred charges[1]	454,359	443,152
Other	1,034,497	983,798
Total deferred income tax liabilities	$5,406,894	$5,365,528
Total net deferred income taxes	$4,098,499	$4,161,547
Classification of net deferred income taxes:		
Included in current liabilities	$ 157,064	$ 227,782
Included in deferred credits	3,941,435	3,933,765
Total net deferred income taxes	$4,098,499	$4,161,547

[1] Represents the portion of the deferred income tax liability related to the revenues required to recover future income taxes.

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

Year ended December 31, (in thousands)	1996	1995	1994
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	3.7	4.8	8.3
Effect of regulatory treatment of depreciation differences	5.9	3.2	3.7
Tax credits—net	(1.4)	(.8)	(1.1)
Other—net	(.8)	(2.1)	(.5)
Effective tax rate	42.4%	40.1%	45.4%

Note 12: Commitments

Capital Projects: Capital expenditures for 1997 are estimated to be $1,773 million for utility, $38 million for Diablo Canyon, and $211 million for diversified operations.

At December 31, 1996, Enterprises had $67 million in firm commitments to make capital contributions for its equity share of generating facility projects. The contributions, payable upon commercial operation of the projects, are estimated to be

$52 million in 1997 (included in the expenditures above) and $15 million in 1998.

Letters of Credit: PG&E utilizes approximately $247 million in standby letters of credit to secure future workers' compensation liabilities.

Qualifying Facilities and Other Power-Purchase Contracts: Under the Public Utility Regulatory Policies Act of 1978, PG&E is required to purchase electric energy and capacity provided by QFs which are cogenerators and small power producers. The CPUC established a series of power-purchase contracts with certain QFs and set the applicable terms, conditions, and price options. Under these contracts, PG&E is required to purchase electric energy and capacity; however, payments are only required when energy is supplied or when capacity commitments are met. The total cost of these payments is recoverable in rates. PG&E's contracts with QFs expire on various dates from 1997 to 2028. Energy payments to QFs are expected to decline in the years 1997 through 2000. Capacity payments are expected to remain at current levels.

In 1996, 1995, and 1994, PG&E negotiated early termination or suspension of certain QF contracts to be paid through 1999 at discounted costs of $25, $142, and $155 million for 1996, 1995, and 1994, respectively. These amounts are expected to be recovered in rates and as such are reflected as deferred charges on the accompanying balance sheet. At December 31, 1996, the total discounted future payments remaining under QF early termination or suspension contracts is $68 million.

QF deliveries in the aggregate account for approximately 19 percent of PG&E's 1996 electric energy requirements, and no single contract accounted for more than 5 percent of PG&E's energy needs.

PG&E also has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, PG&E must make specified semi-annual minimum payments whether or not any energy is supplied (subject to the provider's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the providers. These contracts expire on various dates from 2004 to 2031. The total cost of these payments is recoverable in rates. At December 31, 1996, the undiscounted future minimum payments under these contracts are $34 million for each of the years 1997 through 2001 and a total of $383 million for periods thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately six percent of PG&E's 1996 electric energy requirements, and no single contract accounted for more than five percent of PG&E's energy needs.

The amount of energy received and the total payments made under QF and other power-purchase contracts were:

Year ended December 31, (in millions)	1996	1995	1994
Kilowatt-hours received	26,056	26,468	23,903
QF energy payments	$1,136	$1,140	$1,196
QF capacity payments	$ 521	$ 484	$ 518
Other power purchase payments	$ 52	$ 50	$ 49

Note 13: Contingencies

Nuclear Insurance: PG&E has insurance coverage for property damage and business interruption losses as a member of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL). Under these policies, if a nuclear generating facility of a member utility suffers a loss due to a prolonged accidental outage, PG&E may be subject to maximum assessments of $29 million (property damage) and $8 million (business interruption), in each case per policy period, in the event losses exceed the resources of NML or NEIL.

PG&E has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. An additional $8.7 billion of coverage is provided by secondary financial protection which 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, PG&E may be assessed up to $159 million per incident, with payments in each year limited to a maximum of $20 million per incident.

Environmental Remediation: The Company may be required to pay for environmental remediation at sites where the Company has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or the California Hazardous Substance Account Act. These sites include former manufactured gas plant sites and sites used by PG&E for the storage or disposal of materials which may be determined to present a significant threat to human health or the environment because of an actual or potential release of hazardous substances. Under CERCLA, the Company's financial responsibilities may include remediation of hazardous substances, even if the Company did not deposit those substances on the site.

The Company records a liability when site assessments indicate remediation is probable and a range of reasonably likely cleanup costs can be estimated. The Company reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. Unless there is a better estimate within this range of possible costs, the Company records the lower end of this range (classified as other noncurrent liabilities).

The cost of the hazardous substance remediation ultimately undertaken by the Company is difficult to estimate. It is reasonably possible that a change in the estimate will occur in the near term due to uncertainty concerning the Company's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Company has an accrued liability at December 31, 1996, of $170 million for hazardous waste remediation costs at those sites where such costs are probable and quantifiable. Environmental remediation at identified sites may be as much as $400 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 at sites for which the Company is responsible. This upper limit of the range of costs was estimated using assumptions least favorable to the Company, based upon a range of reasonably possible outcomes. Costs may be higher if the Company is found to be responsible for cleanup costs at additional sites or identifiable possible outcomes change.

The Company will seek recovery of prudently incurred hazardous substance remediation costs through ratemaking procedures approved by the CPUC. The Company has recorded a regulatory asset at December 31, 1996, of $146 million for recovery of these costs in future rates. Additionally, the Company will seek recovery of costs from insurance carriers and from other third parties. The Company believes the ultimate outcome of these matters will not have a material adverse impact on its financial position or results of operations.

Helms Pumped Storage Plant (Helms): Helms is a three-unit hydroelectric combined generating and pumped storage plant with a net investment of $710 million at December 31, 1996. The net investment is comprised of the pumped storage facility (including regulatory assets of $51 million), common plant, and dedicated transmission plant. As part of the 1996 General Rate Case decision in December 1995, the CPUC directed PG&E to perform a cost-effectiveness study of Helms. In July 1996, PG&E submitted its study, which concluded that the continued operation of Helms is cost effective. As a result of the study, PG&E recommended that the CPUC take no action and address Helms along with other generating plants in the context of electric industry restructuring.

PG&E is currently unable to predict whether there will be a change in rate recovery resulting from the study. As with its other hydroelectric generating plants, the Company expects to seek recovery of its net investment in Helms through PBR and transition cost recovery. The Company believes that the ultimate outcome of this matter will not have a material adverse impact on its financial position or results of operations.

Helms became commercially operable in 1984, following delays due to a water conduit rupture in 1982 and various start-up problems related to the plant's generators. As a result of the rupture damage and the operational delay, PG&E incurred additional costs which were excluded from rate base and lost revenues during the period the plant was under repair. In 1994, PG&E submitted for CPUC approval a settlement with the ORA regarding recovery of such additional costs and lost revenues, amounting to approximately $98 million. In September 1996, the CPUC issued a final decision adopting the settlement which permits PG&E to recover that amount. Because PG&E's current rate recovery already reflects the anticipated settlement, adoption of the settlement will have no impact on rates.

Legal Matters:

Cities Franchise Fees Litigation: In 1994, the City of Santa Cruz filed a class action suit in a state superior court (Court) against PG&E on behalf of itself and 106 other cities in PG&E's service area. The complaint alleges that PG&E has underpaid electric franchise fees to the cities by calculating those fees at different rates from other cities not included in the complaint.

In September 1995, the Court certified the class of 107 cities in this suit and approved the City of Santa Cruz as the class representative. In January and March 1996, the Court made two rulings against certain cities effectively eliminating a major portion of the suit. The Court's rulings do not resolve the suit completely. The cities appealed both rulings. The trial has been postponed pending the cities' appeal.

Should the cities prevail on the issue of franchise fee calculation methodology, PG&E's annual systemwide city electric franchise fees could increase by approximately $14 million and damages for alleged underpayments for the years 1987 to 1996 could be as much as $145 million (exclusive of interest). If the Court's January and March 1996 rulings become final, PG&E's annual systemwide city electric franchise fees for the remaining class member cities not subject to the Court's rulings could increase by approximately $4 million and damages for alleged underpayments for the years 1987 to 1996 could be as much as $39 million (exclusive of interest).

The Company believes that the ultimate outcome of this matter will not have a material adverse impact on its financial position or results of operations.

Hinkley: In 1996, PG&E settled a 1993 lawsuit seeking damages for personal injuries allegedly suffered as a result of exposure to chromium near PG&E's gas compressor station at Hinkley. This lawsuit was settled for the aggregate sum of $333 million, of which $50 million had been paid in 1994, with the remaining $283 million paid in 1996. PG&E had previously reserved $200 million for this litigation and in 1996 recorded an additional reserve of $133 million for this settlement. The settlement does not resolve other pending chromium litigation, described below.

Chromium Litigation: In 1994 through 1996, several civil suits were filed against PG&E on behalf of more than 1,500 individuals. The complaints seek an unspecified amount of compensatory and punitive damages for alleged personal injuries resulting from exposure to chromium in the vicinity of PG&E's gas compressor stations at Hinkley, Kettleman, and Topock.

PG&E is responding to the complaints and asserting affirmative defenses. PG&E 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.

Given the uncertainty, the Company cannot predict the outcome of this litigation. However, the Company believes that the ultimate outcome of this matter will not have a material adverse impact on its financial position or results of operations.

Quarterly Consolidated Financial Data (Unaudited)

Quarterly Financial Data: Due to the seasonal nature of the utility business and the scheduled refueling outages for Diablo Canyon, operating revenues, operating income, and net income are not generated evenly every quarter during the year.

All four quarters of 1996 reflected a decline in price per kilowatt-hours as provided in the modified pricing provisions of the Diablo Canyon rate case settlement, and revenue reductions authorized by the 1996 General Rate Case (GRC) and other related rate proceedings. In addition, maintenance and operating expenses exceeded levels authorized by the GRC.

In the second quarter of 1996, the Company charged to earnings $133 million for the settlement of a litigation claim. Revenues were also reduced due to a greater number of scheduled refueling days and unscheduled outages.

In the third quarter of 1996, the Company took charges against earnings of $182 million for contingencies related to gas transportation commitments.

In the fourth quarter of 1996, the Company charged to earnings $59 million in write-downs of nonregulated investments.

The Company recorded additional litigation reserves of $50 million in the first and third quarters of 1995. Diablo Canyon scheduled refueling days and unscheduled outages reduced earnings per common share in the fourth quarter of 1995.

The Company's common stock is traded on the New York, Pacific, and Swiss stock exchanges. There were approximately 198,000 common shareholders of record at December 31, 1996. Dividends are paid on a quarterly basis, and net cash flows are sufficient to maintain the current payment of dividends.

Quarter ended (in thousands, except per share amounts)	December 31	September 30	June 30	March 31
1996				
Operating revenues	$2,700,686	$2,521,852	$2,138,666	$2,248,768
Operating income	508,970	524,846	288,375	573,394
Net income	149,030	233,695	111,780	260,704
Earnings per common share	.34	.55	.25	.61
Dividends declared per common share	.30	.49	.49	.49
Common stock price per share				
High	24.25	23.88	23.75	28.38
Low	20.88	19.50	21.50	22.38
1995				
Operating revenues	$2,227,224	$2,637,653	$2,448,641	$2,308,247
Operating income	451,674	781,912	820,370	709,029
Net income	227,085	377,593	405,520	328,687
Earnings per common share	.48	.85	.92	.73
Dividends declared per common share	.49	.49	.49	.49
Common stock price per share				
High	30.63	30.00	29.75	25.75
Low	27.13	28.38	24.75	24.25

Report of Independent Public Accountants

To the Shareholders and the Board of Directors of PG&E Corporation:

We have audited the accompanying consolidated balance sheet and the statement of consolidated capitalization of PG&E Corporation (a California corporation) and subsidiaries as of December 31, 1996, and 1995, and the related statements of consolidated income, cash flows, common stock equity, preferred stock and preferred securities, and the schedule of consolidated segment information for each of the three years in the period ended December 31, 1996. These financial statements and schedule of consolidated segment information are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules 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 consolidated financial statements and schedule of consolidated segment information referred to above present fairly, in all material respects, the financial position of PG&E Corporation and subsidiaries as of December 31, 1996, and 1995, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP
San Francisco, California
February 10, 1997

Responsibility for Consolidated Financial Statements

The responsibility for the integrity of the consolidated financial statements and related financial information included in this report rests with management. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles appropriate in the circumstances and are based on the Company's best estimates and judgments after giving consideration to materiality.

The Company maintains systems of internal controls supported by formal policies and procedures which are communicated throughout the Company. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and to produce the records necessary for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on the recognition that the costs of such systems should not exceed the benefits to be derived. The Company believes its systems provide this appropriate balance. In addition, the Company's internal auditors perform audits and evaluate the adequacy of and the adherence to these controls, policies, and procedures.

Arthur Andersen LLP, the Company's independent public accountants, considered the Company's systems of internal accounting controls and conducted other tests as they deemed necessary to support their opinion on the consolidated financial statements. Their auditors' report contains an independent informed judgment as to the fairness, in all material respects, of the Company's reported results of operations and financial position.

The financial data contained in this report have been reviewed by the Audit Committee of the Board of Directors. The Audit Committee is composed of six outside directors who meet regularly with management, the corporate internal auditors, and Arthur Andersen LLP, jointly and separately, to review internal accounting controls and auditing and financial reporting matters.

The Company maintains high standards in selecting, training, and developing personnel to ensure that management's objectives of maintaining strong and effective internal controls and maintaining unbiased and uniform reporting standards are attained. The Company believes its policies and procedures provide reasonable assurance that operations are conducted in conformity with applicable laws and with its commitment to a high standard of business conduct.

Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company*

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Pacific Gas and Electric Company

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John C. Sawhill
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Chairman of the Board and Chief Executive Officer,
McKesson Corporation
(distributor of pharmaceuticals and health care products)

Stanley T. Skinner
Chairman of the Board and
Chief Executive Officer,
PG&E Corporation and
Pacific Gas and Electric Company

Barry Lawson Williams
President,
Williams Pacific Ventures, Inc.
(venture capital and real estate, consulting, and mediation)

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Executive Committees
Within limits, may exercise powers and perform duties of the Board.

Stanley T. Skinner (Chair)
Harry M. Conger
Robert D. Glynn, Jr.
Richard B. Madden
Mary S. Metz
Carl E. Reichardt

Audit Committees
Review financial statements and internal accounting and control procedures with independent public accountants.

Harry M. Conger (Chair)
C. Lee Cox
William S. Davila
Mary S. Metz
Rebecca Q. Morgan
Barry Lawson Williams

Capital Investment Committee**
Advises on long-term capital investment strategies and recommends specific investment and divestment opportunities.

Carl E. Reichardt (Chair)
Richard B. Madden
Samuel T. Reeves
John C. Sawhill
Barry Lawson Williams

Finance Committees
Recommend long-range financial policies and objectives, and actions required to achieve those objectives.

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Richard A. Clarke
David A. Coulter
Carl E. Reichardt
Stanley T. Skinner
Barry Lawson Williams

Nominating and Compensation Committees
Recommend candidates for nomination as directors, recommend compensation and employee benefit policies and practices, and review planning for executive development and succession.

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Samuel T. Reeves
John C. Sawhill
Alan Seelenfreund

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

Mary S. Metz (Chair)
Richard A. Clarke
William S. Davila
Robert D. Glynn, Jr.
John C. Sawhill

*The composition of the Boards of Directors, Executive Committees, Audit Committees, Finance Committees, Nominating and Compensation Committees, and Public Policy Committees is the same for PG&E Corporation and Pacific Gas and Electric Company.
**A committee of the PG&E Corporation Board of Directors only.

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Robert D. Glynn, Jr.
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Chief Operating Officer

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Bruce R. Worthington
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Controller

Linda Y. H. Cheng
Assistant Corporate Secretary

Eric Montizambert
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Gabriel B. Togneri
Assistant Treasurer

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Senior Vice President and
General Manager,
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Business Unit

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Customer Services

Roger J. Gray
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General Services

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Vice President and Treasurer

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Regulation

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Governmental Relations

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Vice President,
Human Resources

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Senior Assistant
Corporate Secretary

Eric Montizambert
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Gabriel B. Togneri
Assistant Treasurer

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PG&E Enterprises

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President and
Chief Executive Officer of
U.S. Generating Company

Junona A. Jonas
President and
Chief Operating Officer of
Vantus Energy Corporation

Robert Frommer
President of
PG&E Properties, Inc.

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Chairman of the Board of PGT

Stephen P. Reynolds
President and
Chief Executive Officer of PGT

David Tudor
President and
Chief Executive Officer of
Energy Source, Inc.

Michael J. McDanold
Managing Director of
PGT Australia PTY Limited

Shareholder Information

Shareholder Services Office
77 Beale Street, Room 2600
San Francisco, CA 94105-1814
Call Toll Free 1-800/367-7731
Fax 415/973-7831

For financial and other information about PG&E Corporation or Pacific Gas and Electric Company, please visit our site on the World Wide Web at: www.pge.com

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

Manager of Shareholder Services
David M. Kelly
Mail Code B26B
P.O. Box 770000
San Francisco, CA 94177-0001
1-800/367-7731

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

Corporate Secretary
Leslie H. Everett
Mail Code B32
P.O. Box 770000
San Francisco, CA 94177-0001
415/973-2880

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

Manager of Investor Relations
Angela M. Comstock
Mail Code B8C
P.O. Box 770000
San Francisco, CA 94177-0001
415/973-3007

PG&E Corporation
Pacific Gas and Electric Company

General Information
415/973-7000

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 us in the broker's name, or "street name." We do not know the identity of the individual shareholders who hold their shares in this manner—we 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 the Shareholder Services Office. If your certificates are held by a broker (in "street name"), you are not eligible to participate in the Plan.

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 the Shareholder Services Office.

Replacement of Dividend Checks

If you hold stock in your own name and do not receive your dividend check within five business days after the payment date, or if a check is lost or destroyed, you should notify the Shareholder Services Office so that payment may 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 the Shareholder Services Office immediately.

PG&E Corporation
Pacific Gas and Electric Company
Annual Meetings of Shareholders
Date: April 16, 1997
Time: 10:00 a.m.
Location: Masonic Auditorium
1111 California Street
San Francisco, California

A joint notice of the annual meetings, joint proxy statement, and proxy form are being mailed with this annual report on or about March 3, 1997, to all shareholders of record as of February 18, 1997.

10-K Report
If you would like a copy of the 1996 Form 10-K Report to the Securities and Exchange Commission, please contact the Shareholder Services Office, or visit our site on the World Wide Web at: www.pge.com

1997 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 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 "PGE." Local newspaper symbols may vary.

Pacific Gas and Electric Company has 13 issues of preferred stock and one preferred security, all of which are listed on the American and Pacific stock exchanges.

Issue	Newspaper Symbol*
First Preferred, Cumulative, Par Value $25 Per Share	
Redeemable:	
7.44%	PacGE pfQ
7.04%	PacGE pfU
6.875%	PacGE pfX
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 pf I
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 A quips

*Local newspaper symbols may vary

Design: Martin Design Associates
Photography: Portrait: Doug Menuez
Illustration: Greisbach/Martucci

This report is printed on recycled paper.

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