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AUTH.NAME AUTHOR AFFILIATION
SKINNER,S. Pacific Gas & Electric Co.
ANGUS,M.J. Pacific Gas & Electric Co.
RECIP.NAME RECIPIENT AFFILIATION

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Pacific Gas and Electric Company

333 Market Street, Room 1411-A10E
San Francisco, CA 94105
Mailing Address
Mail Code A10E
P.O. Box 770000
San Francisco, CA 94177
415/972-5497
Fax 415/973-8683

Michael J. Angus
Manager
Regulatory and Design Services

March 26, 1996

PG&E Letter DCL-96-081
HBL-96-012

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Docket No. 50-133, OP-DPR-7
Humboldt Bay Unit 3
<u>1995 Annual Financial Report</u>

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.71(b) and 10 CFR 140.15(b)(1), enclosed are 15 copies of PG&E's Annual Report and Financial Information for the calendar year 1995.

Sincerely,

Michael J. Angus

Enclosure

cc: Steven D. Bloom
L. J. Callan
Ira P. Dinitz
Anthony W. Markley
Kenneth E. Perkins
Michael D. Tschiltz

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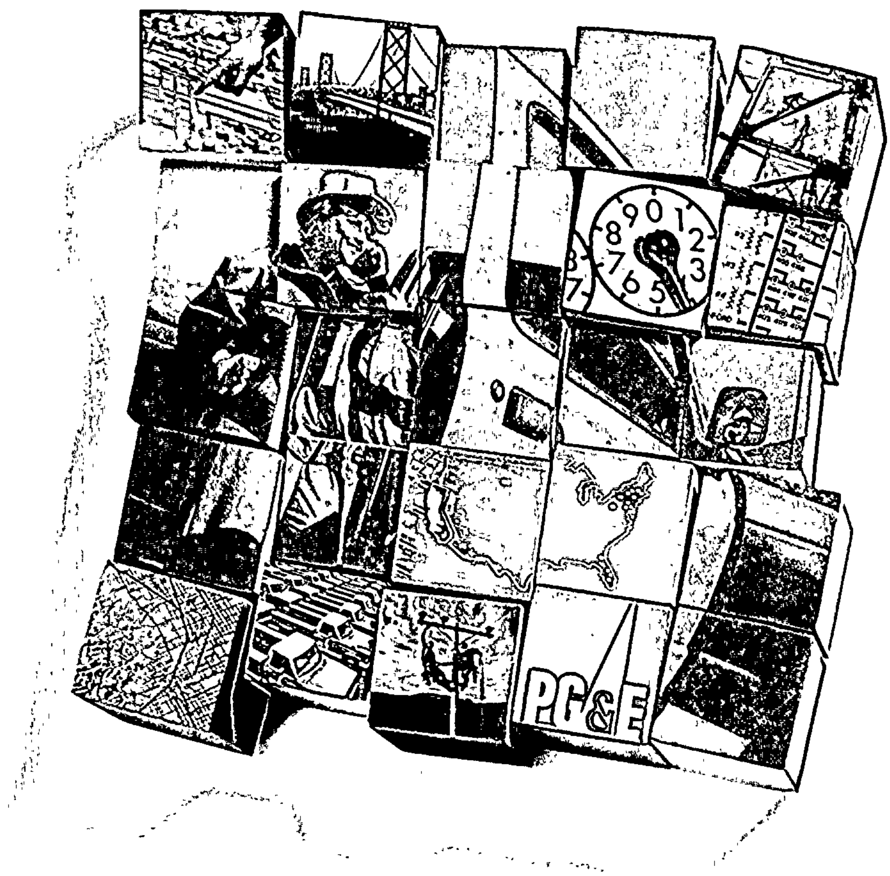
Pacific Gas and Electric Company

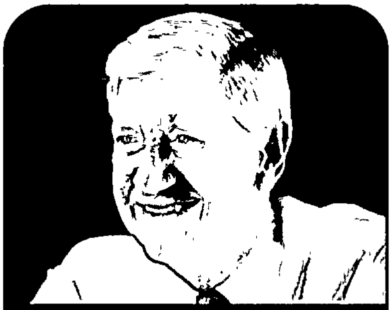


1995
Annual Report

9604010133

Financial Highlights

(dollars in thousands, except per share amounts)	1995	1994	% Change
For the Year			
Operating revenues	$ 9,621,765	$ 10,350,230	(7.0)
Operating income	$ 2,762,985	$ 2,423,786	14.0
Net income	$ 1,338,885	$ 1,007,450	32.9
Earnings available for common stock	$ 1,268,597	$ 949,847	33.6
Earnings per common share	$2.99	$2.21	35.3
Dividends declared per common share	$1.96	$1.96	-
Capital expenditures (including AFUDC)	$ 962,590	$ 1,126,494	(14.5)
Total electric sales to customers (kWh — in thousands)	75,358,632	75,621,150	(0.3)
Total gas sales to customers (Mcf — in thousands)	269,904	306,930	(12.1)
At Year End			
Total assets	$ 26,850,290	$ 27,708,564	(3.1)
Total electric customers	4,408,000	4,361,000	1.1
Total gas customers	3,628,000	3,529,000	2.8
Number of common shareholders	220,000	234,000	(6.0)
Number of common shares outstanding	414,025,586	430,242,687	(3.8)
Number of employees (excluding subsidiaries)	21,000	21,000	-



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

Letter to Shareholders. The close of 1995 marked the end of one era and the start of another for electric utilities in California. This new beginning was ushered in by the California Public Utilities Commission (CPUC) on December 20, 1995, when it issued an order that inevitably will lead to profound changes in the electric utility industry.

The order did not come as a surprise. It is the product of several years of deliberations among regulators, customers and utilities, and preliminary decisions by the CPUC. For years, PG&E has been attuned to the changes coming to our business. We have been working to prepare the company for them and have reported our progress to you in previous annual reports.

The company enters the new era from a position of financial strength.

In 1995, PG&E earned $2.99 per share, compared to the $2.21 per share we recorded in 1994. The 1995 earnings reflect solid operating performance throughout the company's utility business, particularly at Diablo Canyon, which exceeded its targets for power production and contribution to earnings.

Of the $2.99 per share that we earned in 1995, we paid out $1.96 in dividends per common share. This gave us a payout ratio of about 66 percent, compared to an industry average of 77 percent. Our 1995 total return—the combination of stock price appreciation and dividends paid—was about 25 percent.

The company's strong cash flow enabled us to repurchase a net of about $460 million worth of PG&E common stock in 1995 and to retire a net of about $200 million of long-term debt.

Our sound financial condition gives PG&E a firm foundation on which to build the company's response to what promises to be a radically different and uncertain future.

The CPUC order would create a new market framework for the state's electric utility industry to be phased in over the next seven years. Utilities would no longer be "vertically integrated" monopolies, the sole providers of generation, transmission and distribution services. In the new market framework, these services would become three separate businesses.

- Generation would become a competitive "commodity" business. Customers would have the option either to continue to buy their electricity from the local utility or avail themselves of "direct access," buying power from other generators.
- Transmission would remain regulated. But utilities would have to provide open access to their transmission systems to enable competing generators to sell to retail purchasers.
- Distribution would also remain a regulated function. Customers—including those who chose competing electric suppliers—would continue to have their electricity delivered to their home or business by a local distribution company. (Please see accompanying box for additional information on the CPUC restructuring order.)

Although much remains to be done to determine the critical details of how the CPUC's decision will work, it clearly represents a watershed in the electric utility industry. Just as clearly, it raises major issues for all of California's utilities, including PG&E.

Competitive Transition Costs (CTCs). The most fundamental of these will be to recover CTCs, the costs associated with the transition to a more competitive electric supply market.

Electric Restructuring Order in Brief

- **Competitive electric supply market could begin January 1, 1998, for certain customers. All customers could participate by 2003.**
- **Customers would have the option of buying power from their local utility or from another generator.**
- **A power exchange would be created to operate as a wholesale power pool. California investor-owned utilities (IOUs) would be required to sell the power they generate to the exchange.**
- **The exchange would set the market price, and the IOUs would be required to buy their power from the exchange at that market price. Other generators could participate in the exchange voluntarily.**
- **Utilities would be required to turn over operational control of their transmission systems to an "Independent System Operator" (ISO). The ISO would ensure transmission service is provided on a nondiscriminatory basis using standard pricing arrangements.**
- **Utilities would have the opportunity to recover past investments in generation and other assets that might not be competitive in a restructured market. Retail customers would pay a surcharge to offset these costs, but this surcharge could not increase electric prices to a level above prices in effect January 1, 1996.**

More specifically, CTCs represent those costs we incurred under the traditional regulatory framework that now are above market and could not be recovered under market-based pricing. An example would be a power plant built by PG&E many years ago that today cannot generate electricity at a price competitive with a more modern plant using advanced technology.

The order provides an opportunity for the company to recover its power purchase obligations, past investments in power plants and other assets that might not be competitive in a restructured industry. However, the extent to which we will be able to achieve this recovery cannot now be determined.

Diablo Canyon presents a similar challenge. The December 20 order states that the commission will continue to honor regulatory commitments regarding the recovery of nuclear power costs. However, many details of how recovery of the company's investment in Diablo Canyon will be accomplished remain to be determined.

CTC recovery and other elements of the CPUC order challenge our ability to maintain the strength and profitability of our utility business.

But over the longer term, we're confident the company can meet this test and pursue new, profitable opportunities for growth.

Our employees understand the forces driving electric restructuring. Through a new partnership, we have established a strong, cooperative relationship with our unions. And the company continues to take major steps to make our utility business more competitive.

Competitive Prices. For several years PG&E has been working to lower the prices we charge for gas and electricity. Our residential gas rates are now almost 10 percent below 1995 levels and 8.2 percent below the national average.

We are substantially ahead of schedule in meeting our price-cutting goal for electricity. The target we established in 1995 was to cut PG&E's systemwide average electric price of 10.5 cents per kilowatthour (kwh) to 10 cents per kwh or lower by the end of 1999. We have already attained that goal. At the start of 1996, PG&E's systemwide average electric price was 9.9 cents per kwh.

In real, inflation-adjusted terms, we have decreased our systemwide average electric price by 16 percent since 1993.

Customer Service. Our efforts to improve customer service are just as intense. In addition to the daily search for ways to improve service to customers, PG&E is engaged in a series of long-range programs to streamline all the processes that help the company meet customer needs.

From added staffing in our consolidated phone centers to stepped up maintenance of our electric system, from telecommunications upgrades to intensified tree trimming, PG&E is redoubling its efforts to deliver energy safely, reliably and responsively.

The severe storms of 1995 strained the company's facilities and communication capabilities. But they also demonstrated the courage and commitment of PG&E employees—particularly our field crews and customer service representatives, who worked with dedication and skill throughout these emergencies.

As the company moves into a more competitive future, it is apparent that PG&E needs organizational structures, at both the operating and overall corporate levels, that reflect the changes that are coming.

In 1995, we separated our Electric Supply Business Unit into two organizations. "Electric Generation" will oversee all of the company's fossil-fuel, hydro and geothermal plants, as well as Diablo Canyon. "Electric Transmission" will be responsible for PG&E's high-voltage transmission system. These units align our utility organization more closely with the way we see the electric industry evolving.

At the overall corporate level, the Board of Directors and management are proposing the formation of a holding company, which is a commonly used structure throughout the utility industry.

The holding company structure would enable the company to respond more efficiently and effectively to competitive changes occurring in the gas and electric industries. That is why the company is asking for your vote to approve this proposal. More information on the holding company proposal is contained in the Proxy Statement and Prospectus enclosed with this report.

Looking To The Future. While electric restructuring is being designed, discussed and debated in regulatory hearing rooms around the U.S., it is already happening in other nations.

From Australia to Great Britain, governments are privatizing electric distribution companies. From Chile to India, demand for energy is growing. Together, these create opportunities to acquire, build and operate electric distribution, generation and gas transport facilities around the world. So, as we look to the future, we believe international opportunities present, over time, significant growth potential for the company. Here at home, we look to the future with a confidence born of our past success. We have faced many hurdles in the past. We have cleared them all. We have found ways to strengthen the company, maintain its financial integrity, and provide a solid foundation for growth and industry leadership.

Among PG&E's hallmarks are resiliency and adaptation to change that have benefited our customers, shareholders and employees alike.

We continue to possess the attributes needed to overcome the very real challenges that lie ahead and build on our long history of success.

Stanley T. Skinner

Stanley T. Skinner

Chairman of the Board and Chief Executive Officer

February 12, 1996

Distribution

Success in our utility business will depend in the future—as it does today—on delivering safe, reliable, responsive energy services at competitive prices. PG&E's

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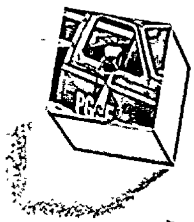
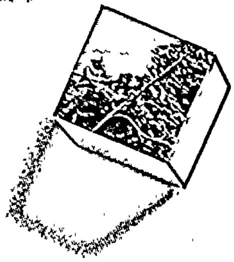




Distribution. In the restructured energy utility industry that is evolving in California, customers would continue to have gas and electricity delivered to their door by a local distribution company, or LDC—in all likelihood, the local utility.

This business would remain a highly regulated monopoly. In lieu of competition, LDCs would retain the obligation to serve, ensuring that all customers in the LDC's service area would have access to safe, reliable gas and electric supplies.

Prices for distribution service would probably be determined through "performance-based ratemaking" (PBR). Under traditional regulation, rates are generally based on the utility's cost of providing service, plus a return on its capital investment.

Under PBR, prices would be determined by regulators, factoring in inflation and productivity. This system would permit an LDC to achieve a fair return on investment if it met performance targets set by regulators.

Controlling costs would continue to be essential to earning attractive returns in the distribution business. Providing safe, reliable and responsive customer service would be just as critical to success.

If customers were satisfied, regulators would allow the LDC to charge reasonable prices for its services, and the threat of municipalization—local governments taking over the distribution function in their jurisdiction—would be reduced.

PG&E is fully aware of the challenges a restructured distribution business presents and is aggressively taking action to improve operations and the service we provide.

employees understand the forces driving change and are redoubling their efforts to improve the way we meet customer needs and control costs.

Following heavy storms early in the year, the company allocated an additional $180 million to accelerate electric system maintenance and increase responsiveness to customer needs. We added 250 customer service representatives and more than 400 lines to our four consolidated phone centers. And we substantially augmented our tree-trimming program.

In December, extremely violent wind and rain storms struck Northern and Central California, causing some 1.7 million electric service interruptions. Although 85 percent of those affected had service restored within 48 hours, our ability to communicate effectively with customers met neither their expectations nor ours.

Finding new, more effective ways to provide customers with accurate and timely information in storm emergencies is an immediate priority.

In the longer term, we are committed to improve PG&E service with advanced technology. For example, we plan to replace our Customer Information System (CIS) with a more flexible system capable of meeting customer needs more rapidly. CIS is the computerized network that bills, services and provides vital information and energy usage data on PG&E's eight million gas and electric accounts.

We plan to install more than 1,200 mobile data terminals and related software in the company's service vehicles. This system will greatly increase our ability to schedule service call appointments at convenient times for customers and provide accurate, timely information on their service.

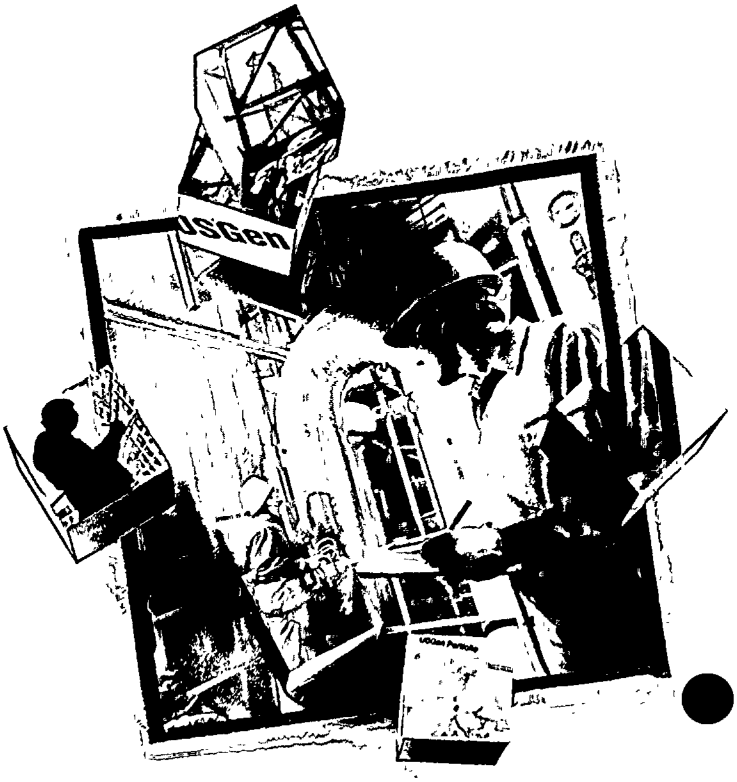
Similarly, we intend to install a new customer outage information system. Among many capabilities, this system will identify the location, size and probable cause of an electric outage, speeding restoration of service.

Excellent customer service and cost-cutting efficiency are two key elements to a successful gas and electric distribution business. But providing energy services safely is just as high a priority. The company is reemphasizing the need to prevent accidents that can injure members of the public and employees, and damage property.

Despite the ferocity of the December storms and the inherent danger of repairing electric lines under such conditions, our people restored service during that emergency without a significant injury to themselves or the public. We are proud of that record. It is one we are working hard to duplicate in every job we do, every hour of every day of the year.

Generation. Competition in the generation segment of the electric utility industry is nothing new. It dates back to the Public Utility Regulatory Policies Act of 1978 (PURPA), which Congress enacted in response to soaring power prices caused by the Arab oil embargoes of the 1970s.

PURPA opened the market to non-utility generators. Privately owned Qualifying Facilities (QFs), generators whose power utilities were required to buy, and Independent Power Producers (IPPs) proliferated and prospered.



California took a major step in 1995 toward creating a new world for the electric industry. It would be a world of competition where price matters, customers

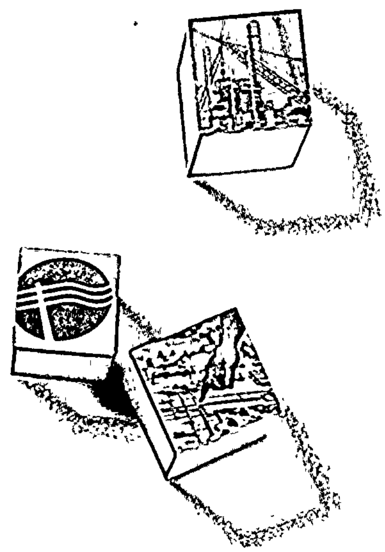
Prior to PURPA, PG&E owned virtually every generating plant in Northern and Central California. In 1995, we owned just over half of the plants in the region and generated about 66 percent of the power we sold.

The National Energy Policy Act of 1992 moved us closer to a competitive energy market by authorizing open access to the nation's transmission system for the wholesale electric market. Acting on the Congressional authorization, the Federal Energy Regulatory Commission last year opened the nation's transmission lines to wholesale transmission.

The CPUC restructuring order would complete this transition to a fully competitive electric supply market, one in which customers would have access to an array of generators, and the market—not regulators—would set the price of power.

This framework raises a concern about utilities' ability to influence a competitive electric supply market because of the amount of generating capacity they own. To mitigate this influence, the CPUC order would require utilities to file a plan to divest themselves of at least half of their fossil generating assets. But it remains unclear how and when divestiture would be accomplished.

In considering divestiture, the commission appears to be following the restructuring model in several foreign countries which have totally separated generation from distribution in their electric industries.



could choose to buy their power from the local utility or from another generator, and the marketplace would determine an energy utility's success or failure.

In a restructured energy utility business, PG&E's huge transmission system would become the conduit connecting customers with their choice of competitive genera-

Another issue raised by the recent order is the exact role utility-owned subsidiaries engaged in independent power production could play in the newly deregulated market.

What is certain, however, is that in a fully competitive generation market, safe and efficient plant operations are absolutely essential to success. PG&E brings a strong record of excellent power plant performance to this new era.

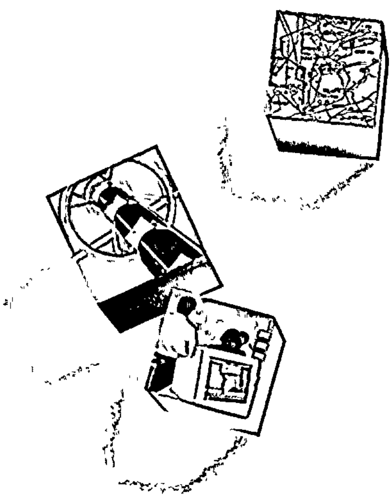
For example, Diablo Canyon has received the Institute of Nuclear Power Operations' highest rating for safety, operating efficiency and low incidence of forced outages five consecutive times. Diablo Canyon shares this distinction with only one other nuclear power plant in the nation.

In 1995, Diablo Canyon achieved a capacity factor of 86 percent, generated 16.3 billion kilowatthours of electricity and contributed $1.16 per share to corporate earnings.

PG&E also has shown its ability to anticipate and take advantage of changes occurring in the generation business. In the late 1980s, the company recognized the opportunities created by a growing national IPP industry.

Today, through U.S. Generating Company, a partnership with Bechtel Enterprises, Inc., we are the second largest IPP in the U.S., with nearly 3,400 megawatts in generation assets.

These include 14 independent power plants in operation and three under construction across the country.



Transmission

tors. PG&E would still own the wires and towers, but operational control would be in the hands of an independent system operator ensuring equal access.

Transmission. Under the CPUC restructuring order, operation of investor-owned utility (IOU) transmission systems in California would be controlled by an Independent System Operator (ISO). The ISO would be independent from utilities and generators. Its primary function would be to operate the transmission systems for the IOUs and to dispatch generation in accordance with safety and reliability standards.

PG&E would continue to own and maintain its transmission wires, towers and equipment. PG&E would also physically operate the system under the direction of the ISO.

The Federal Energy Regulatory Commission (FERC) regulates price, terms and conditions of wholesale transmission service. The CPUC regulates integrated generation-transmission-distribution retail service. Unbundled transmission service as proposed by the CPUC order would place PG&E's transmission assets under FERC jurisdiction.

Restructuring in the natural gas industry already has unbundled much of our gas business. For example, PG&E's natural gas transmission business for several years has been separated from the procurement and distribution functions.

The company earns on the gas transportation services to buyers. This segment of the business offers opportunities for expansion. For example, in 1995, Pacific Gas Transmission, a subsidiary of PG&E, added two extensions to its mainline system. The additional pipelines are bringing Canadian gas to WP Natural Gas in southern Oregon and an electric plant owned by Portland General Electric.

Selected Financial Data

(In thousands, except per share amounts)	1995	1994	1993	1992	1991
For the Year					
Operating revenues	$ 9,621,765	$10,350,230	$10,550,002	$10,315,713	$ 9,823,137
Operating income	2,762,985	2,423,786	2,560,235	2,699,824	2,550,334
Net income	1,338,885	1,007,450	1,065,495	1,170,581	1,026,392
Earnings per common share	2.99	2.21	2.33	2.58	2.24
Dividends declared per common share	1.96	1.96	1.88	1.76	1.64
At Year End					
Book value per common share	$20.77	$20.07	$19.77	$19.41	$18.40
Common stock price per share	28.38	24.38	35.13	33.13	32.63
Total assets	26,850,290	27,708,564	27,145,899	24,188,159	22,900,670
Long-term debt and preferred stock and preferred securities with mandatory redemption provisions (excluding current portions)	8,486,046	8,812,591	9,367,100	8,525,948	8,341,310

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 Consolidated Financial Statements.

Pacific Gas and Electric Company (PG&E) and its wholly owned and controlled subsidiaries (collectively, the Company) are engaged principally in the business of supplying electric and natural gas services. PG&E is a regulated public utility which provides generation, procurement, transmission and distribution of electricity and natural gas to customers throughout most of Northern and Central California. Pacific Gas Transmission Company (PGT), a wholly owned subsidiary, transports gas from the Canadian border to the California border and the Pacific Northwest. The Company's operations are regulated by the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission (NRC), among others.

Building on its expertise in the energy industry, the Company is also expanding its diversified operations, principally through its wholly owned subsidiary, PG&E Enterprises (Enterprises). Enterprises, through its subsidiaries and affiliates, develops, owns and operates electric projects around the world, as discussed further in the Diversified Operations section.

The following discussion includes some forward looking information. Importantly, the ultimate impact of increased competition and the changing regulatory environment on future results is uncertain but is expected to cause fundamental changes in the way PG&E conducts its business and to make earnings more volatile. This outcome 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: Under traditional utility regulation, utilities have been accorded the right to serve customers within designated areas in return for their commitment to provide service to all who request it. Regulation was designed in part to take the place of competition to ensure that utility services were provided at fair prices. However, recent changes in both the gas and electric industries have allowed competition to develop in the gas supply and electric generation segments of PG&E's business, resulting in fundamental changes in the way PG&E's various services are regulated and managed.

Electric Industry: PG&E currently performs the functions of electric generation, transmission, distribution and customer service. However, competition from nonutility and nonregulated electric suppliers and self-generation and cogeneration have provided some major utility customers with alternative sources to satisfy their electric supply needs. Currently, PG&E obtains a portion of its electric supply from generation sources outside its service territory and from qualifying facilities, or QFs (small power producers or cogenerators that meet certain federal guidelines qualifying them to supply generating capacity and electric energy to utilities), owned and operated by independent power producers (IPPs).

Regulatory changes enacted at the federal level and those contemplated at the state level have transformed and will continue to transform the electric transmission function by promoting open access to nonutility suppliers. At the federal level, the National Energy Policy Act of 1992 reduced various restrictions on the operation and ownership of IPPs and provided them and other wholesale suppliers and purchasers with increased access to electric transmission lines throughout the United States.

The FERC has established a Notice of Proposed Rulemaking (NOPR) on open access. The NOPR requires that all utilities offer open access wholesale transmission service that is comparable to the wholesale transmission service that utilities provide themselves. In addition, the FERC accepted, subject to refund and the outcome of the NOPR, PG&E's proposed open access wholesale electric transmission tariffs, effective July 1, 1995. These tariffs generally conform to the FERC NOPR.

On December 20, 1995, the CPUC issued a decision calling for the restructuring of California's electric industry. The CPUC's goal is to provide a structure that will ultimately allow California consumers to choose among competing suppliers of electricity. In summary, the decision would (1) simultaneously create a wholesale power pool (the Exchange) and allow direct access for certain customers to contract directly with electric generation providers beginning in 1998; (2) establish an Independent System Operator (ISO) to manage and control the transmission system; and (3) provide recovery of utilities' stranded costs (costs which are above-market and could not be recovered under market-based pricing) through a surcharge, or competition transition charge (CTC), to be imposed on all customers taking retail electric services as of or after December 20, 1995. The decision, while effective immediately, provides a 100-day period for legislative review and sets out an ambitious schedule for various implementation filings and comments over the period ending in September 1996.

Under the restructuring decision, investor-owned utilities (IOUs) would continue to provide distribution, generation and procurement functions for those customers choosing to take bundled service from utilities, all of which would be regulated under performance-based ratemaking. The decision requires the IOUs to file proposals to establish performance-based ratemaking for the generation and distribution functions. The decision provides that by January 1, 1998, a representative number of customers from all customer groups, individually or in the aggregate, will be able to participate in the first phase of direct access which will last one year, with the balance of customers phased in to direct access within five years. Ultimately, it is contemplated that all customers will have the choice of buying electricity from their utility, the Exchange or directly from electric generation providers through direct access bilateral contracts.

The decision requires the three largest IOUs, in conjunction with other interested parties, to work together to prepare a joint proposal for the creation of the Exchange which will be separate from and independent of the ISO. The Exchange would manage bids for energy, set the market clearing price and then submit its delivery schedule to the ISO for dispatch. The IOUs would be required to bid all their generation output into the Exchange and purchase all their energy from the Exchange during the five-year transition period to full direct access. Participation in the Exchange would be voluntary for all other market participants.

The decision also requires the three largest IOUs to develop a detailed proposal for submission to the FERC for creation of the ISO. The decision contemplates that the IOUs, after approvals from the FERC and the CPUC, turn over control, but not ownership, of their transmission systems to the ISO. The ISO will control the power dispatch and transmission system and provide transmission service on a nondiscriminatory basis.

The CPUC concluded that market power issues associated with the electric industry restructuring almost certainly mandate that the IOUs divest themselves of a substantial portion of their fossil fuel generation assets. Accordingly, the decision requires that the three IOUs file plans to voluntarily divest themselves of at least 50 percent of their fossil fuel generation assets. To encourage divestiture, for each ten percent of fossil fuel generation capacity divested, the decision proposes an increase of up to ten basis points in the equity return on the undepreciated net book value of fossil fuel generation assets. The decision also directs the IOUs to file comments within 90 days on the feasibility, timing and consequences of a corporate restructuring to separate their operations and assets between the generation, transmission and distribution functions, including the option of forming a holding company structure. In response, PG&E is considering a range of possible alternatives, including the possible divestiture of a substantial portion of its generation assets.

The decision provides for the collection of transition costs through the imposition of a non-bypassable CTC applied to transmission and distribution rates. Transition cost recovery shall not increase rates beyond the rate levels in effect as of January 1, 1996. A transition cost account will be established for each utility. Transition costs associated with regulatory assets will be included in the account as authorized by the CPUC. The account will be adjusted annually for the difference between authorized revenues associated with the generation assets and actual revenues earned in the market as well as after a generation asset receives its market valuation. Valuation of above-market generation assets will be completed by 2003. Utility nonnuclear generation assets will be valued through sale, spin-off or market appraisal. The CTC will include the undepreciated book value of a utility's fossil fuel generation assets as reflected in rate base at a reduced return on equity equal to ten percent below the utility's embedded cost of debt. For hydroelectric and geothermal generation assets, the CTC will be the above- or below-market portion of the revenue requirement for those facilities derived through a performance-based ratemaking method.

Transition costs resulting from the operation of nuclear generation facilities and electricity purchases under existing wholesale and QF contracts will also be recorded in this account. Transition costs for these resources will be calculated annually over the terms of the contracts or until the authorized transition cost recovery has been completed. Except for existing QF generation contracts with contractual payments beyond 2003, all transition costs will be collected by 2005.

With respect to recovery of costs associated with Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the Diablo Canyon rate case settlement (Diablo Settlement), the decision confirms that the CPUC will continue to honor regulatory commitments regarding the recovery of nuclear generation costs. The decision provides that transition costs associated with Diablo Canyon will be calculated over the term of the Diablo Settlement as the difference between the revised Diablo Settlement price and the market price as determined by the Exchange and the ISO will schedule power from Diablo Canyon on a must-take basis, consistent with the Diablo Settlement. The decision requires PG&E to file a proposal for pricing Diablo Canyon generation at market prices by 2003 and for completing recovery of Diablo Canyon CTC by 2005 while assuring no overall rate increase over January 1, 1996, levels. If PG&E retains ownership of Diablo Canyon, decommissioning costs will also be included in the transition cost account. The CPUC requires that at least one of the alternatives presented in PG&E's proposal shall be structured to accelerate recovery of the undepreciated portion of Diablo Canyon, at a significantly reduced return tied to the embedded cost of debt, and to include performance-based ratemaking for recovery of operating costs and prospective capital additions.

Two commissioners voted for a minority proposal which differed from the decision in the following significant respects: (1) phase-in of direct access for all customers would be over a twelve-month period; (2) participation in the wholesale power pool would be voluntary for all participants; and (3) withholding of ten percent of total allowable transition costs would be used as a disincentive for utilities to retain the current level of generation ownership until such time that 50 percent of current utility-owned generation, excluding nuclear plants, is divested.

Financial Impact of the Electric Industry Restructuring: In December 1994, in response to one of the proceedings leading to the decision, PG&E estimated the revenue requirements of its owned generation assets and power purchase obligations to be above market by $3 billion and $11 billion at assumed market prices of $.040 and $.032 per kilowatt-hour (kWh), respectively. These market prices were used to provide a range of possible transition costs and do not represent a forecast of expected market prices. These above-market estimates were determined by comparing future revenue requirements of generation assets and power purchase obligations, over a 20-year and 30-year period, respectively, with revenues computed at assumed market prices. The revenue requirements for Diablo Canyon and all PG&E-owned generation assets included a return on investment. Diablo Canyon was included in the revenue requirements calculation using the revised pricing included in the modified Diablo Settlement. (See Note 4 of Notes to Consolidated Financial Statements.) The above-market revenue requirements for Diablo Canyon included above were $4 billion and $6 billion at assumed market prices of $.040 and $.032 per kWh, respectively. At this time, PG&E has not completed a more current estimate of its above-market revenue requirements. However, market prices could be less than $.032 per kWh. The actual amounts of above-market revenue requirements may differ materially from those indicated above and will depend on the final regulations and the actual market prices of electricity or a definitive market valuation.

The CPUC electric industry restructuring decision establishes an account to track the accumulation of transition costs and their recovery. While the decision provides an opportunity for recovery of all above-market costs, actual recovery of the CTC will be limited to an amount that does not increase the customers' aggregate rates above those in effect on January 1, 1996. Recent CPUC decisions effective on January 1, 1996, including PG&E's General Rate Case (GRC), have resulted in an average electric system rate of 9.9 cents per kWh. PG&E's ability to recover its transition costs will be dependent on achieving overall reductions in costs such that it can recover its ongoing operating costs, capital costs and transition costs at the 1996 rate level and on continuing to collect CTC for the duration of the recovery period.

As a result of applying the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (see Note 1 of Notes to Consolidated Financial Statements), PG&E has accumulated approximately $2.6 billion of electric regulatory assets, including balancing accounts, at December 31, 1995. The regulatory assets attributable to electric generation, excluding balancing accounts of $248 million which are expected to be recovered in the near term, were approximately $1.5 billion at December 31, 1995. When generation rates are no longer based on cost of service, as ultimately contemplated under the decision, PG&E will discontinue application of SFAS No. 71 for that portion of its business. However, PG&E expects to recover its regulatory assets as transition costs through the CTC and does not expect a material loss from the discontinuance of SFAS No. 71. PG&E's transmission and distribution businesses are expected to remain on cost-of-service rates.

In addition, the adoption of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," in 1996 will require that regulatory assets continue to be probable of recovery in rates. In the event that this criterion can no longer be met, whether due to changing regulation or PG&E's inability to collect these costs, applicable portions of any regulatory assets would be written off. The transition cost account will be a regulatory asset also subject to the criteria of SFAS No. 121.

The CPUC decision provides a structure for full recovery of PG&E's generation investments and costs through market prices and the CTC. However, market pricing of Diablo Canyon by 2003, possible divestiture of generation assets and lower returns on a portion of its investments in fossil fuel generation assets will adversely impact PG&E's future returns on its generation investments. The Diablo Canyon investment and the related Diablo Settlement will represent a major portion of PG&E's transition costs. Current recovery of this investment is occurring through 2015, the period of the Diablo Settlement. Adjusting Diablo Canyon generation to market prices by 2003 would require an acceleration in recovery of undepreciated plant costs. The net book value of PG&E's investment in Diablo Canyon was approximately $4.8 billion at December 31, 1995. The net book value of the remaining PG&E-owned generation assets, including an allocation of common plant, was approximately $3.1 billion at December 31, 1995.

Because of the expected transition cost recovery as provided in the decision, PG&E does not anticipate a material impairment loss on its investment in generation assets due to electric industry restructuring. However, should final regulations differ significantly from the CPUC decision or should full recovery of generation assets and obligations not be achieved due to changing costs or limitations imposed by the market, a material loss could occur.

The Company cannot predict the ultimate outcome of the ongoing changes that are taking place in the electric utility industry or predict whether such outcome will have a material impact on its financial position or results of operations. However, the Company believes the end result will involve a fundamental change in the way it conducts business. These changes will impact financial operating trends, resulting in greater earnings volatility.

Gas Industry: Restructuring of the natural gas industry has given customers greater options in meeting their gas supply needs. Industrial and large commercial (noncore) customers have the option of buying gas directly from the supplier of their choice and purchasing from PG&E transmission and distribution services only. In the latter half of 1993, even greater numbers of noncore customers began purchasing their own gas with the implementation of FERC Order 636 and the CPUC's capacity brokering program. FERC Order 636 required interstate pipeline companies, including PGT, to unbundle their services into separate sales, transportation and storage services. The CPUC's capacity brokering program required California utilities to release firm capacity on interstate pipelines that they no longer needed. These changes have made it easier for customers to purchase gas directly from suppliers.

Certain customers can also use alternative transportation services provided by competing companies. The FERC has approved the expansion of a competing company's natural gas pipeline into PG&E's service territory. If this expansion takes place, this pipeline could compete directly for transportation service to several of PG&E's large customers and result in the loss of sales on PG&E's gas transportation system.

While noncore customers have had options in the gas marketplace, residential and smaller commercial (core) customers have had more limited opportunities in choosing their gas suppliers. Currently, substantially all core customers receive bundled services from PG&E. PG&E purchases and delivers gas to these customers and prices such service as a package.

In an effort to promote competition and increase options for all customers, as well as to position itself for success in the competitive marketplace, PG&E is actively pursuing changes in the California gas industry. In October 1995, PG&E presented a proposal, called the "Gas Accord," to numerous parties active in the California gas marketplace, including consumer groups, industrial customers, shippers and marketers. PG&E has invited these parties to join it in a collaborative effort to develop a restructuring of the California gas marketplace.

The Gas Accord proposes three broad initiatives:

(1) Increased Customer Choice — Under the Gas Accord, PG&E proposes to give all customers greater ability to choose their gas suppliers in the future. PG&E has formed an advisory group to help it design a program that will facilitate opening the core market for full competition.

(2) Separation of Transmission and Distribution Service and Rates — PG&E proposes to charge separately for, or unbundle, its gas transmission and distribution services. This would give noncore customers and gas suppliers more flexibility with respect to the purchase of gas transportation services. The proposed unbundled gas transmission and distribution rates would continue to recover PG&E's cost of service. Accordingly, PG&E believes it would be able to continue the application of SFAS No. 71 for a majority of its gas business.

(3) Resolution of Existing Regulatory Issues — PG&E also proposes to settle several outstanding gas regulatory issues that are currently pending at the CPUC in separate proceedings. These issues include recovery of costs related to PG&E's capacity commitments with Transwestern Pipeline Company, PG&E's capacity commitments with El Paso Natural Gas Company and PGT related to its noncore customers, and the PG&E portion of the PGT/PG&E Pipeline Expansion Project (Pipeline Expansion). (See Note 3 of Notes to Consolidated Financial Statements.)

Negotiations on the Gas Accord began in October 1995. Any agreement reached by PG&E and other parties must be approved by the CPUC before it may be implemented. The Company believes the ultimate outcome of the Gas Accord negotiations, including resolution of gas regulatory issues, will not have a material impact on its financial position or results of operations.

Holding Company Structure: In October 1995, the Board of Directors (Board) of PG&E authorized management to seek appropriate shareholder and regulatory approvals for the formation of a holding company structure. Under such structure, the holders of common stock of PG&E would become the holders of common stock of a new holding company which, in turn, would own all the common stock of PG&E. PG&E would become a subsidiary of the new holding company. The debt and preferred stock of PG&E would remain outstanding at the PG&E level and would not become obligations or securities of the holding company.

This transaction would not result in any change in PG&E's ownership of California utility operations, which currently are conducted by PG&E and represent substantially all of the assets, revenues and earnings of the consolidated group. It is intended that PG&E's ownership interest in PGT and Enterprises would be transferred to the holding company. These two wholly owned subsidiaries represented approximately eight percent of the Company's consolidated assets and four percent of the Company's consolidated net income at December 31, 1995.

The Company believes that the formation of a holding company will help the Company to respond more effectively and efficiently to competitive changes taking place in the utility industry and to new business opportunities that may arise from those changes. This structure should enhance the financial separation of the Company's California utility business from its other businesses and also provide greater financing flexibility.

The Company will be seeking approval of the transaction from the CPUC, the FERC and the NRC. Shareholders will be asked to approve the transaction at the annual meeting in April 1996. The Company intends to form the holding company structure by the end of 1996. However, approval from the regulatory agencies could have an effect on the timing.

Utility Revenue Matters: In addition to the CPUC decision on electric industry restructuring (discussed above and in Note 2 of Notes to Consolidated Financial Statements) and various gas proceedings (see Note 3 of Notes to Consolidated Financial Statements), there are other regulatory matters with respect to revenues and costs which will affect PG&E's rates in 1996 and beyond. In December 1995, the CPUC issued its decision in PG&E's 1996 GRC. (See below for further discussion.) Based on the GRC decision and the consolidation of the electric rate cases that became effective January 1, 1996, including the energy cost, cost of capital and various other proceedings, PG&E's electric revenue will decrease by $443 million from rates in effect in 1995. The GRC decision and various gas proceedings will also result in an overall gas revenue decrease of $211 million. The more significant of these gas and electric proceedings are discussed below.

The 1996 GRC decision for base rates effective January 1, 1996, authorized electric and gas base revenue decreases of approximately $300 million and $270 million, respectively, compared to rates in effect in 1995. The $570 million revenue decrease is attributable to declining capital expenditures, lower cost of capital and reductions in expense levels, principally relating to workforce reductions.

The GRC proceeding has been held open to consider, among other things, PG&E's response to outages caused by recent storms and a study to determine the cost effectiveness of the Helms pumped storage facility (Helms). The study will consider changes in rate recovery for the plant which will include, among other things, the option of retirement with recovery of the investment without a return. Helms had a net book value of $631 million at December 31, 1995.

In December 1995, PG&E's service territory experienced severe storms and winds which caused approximately 1.7 million electric service interruptions. The assigned commissioner in the 1996 GRC subsequently issued a ruling which ordered hearings on various issues arising out of PG&E's response to those wind storms. The hearings will also address potential remedies, including reparations to customers for reduced reliability, penalties, disallowances and damages to customers for property loss.

In December 1995, the CPUC issued its decision in PG&E's 1996 electric energy cost proceeding authorizing a revenue decrease of $112 million due primarily to lower gas costs, lower Diablo Canyon generation costs, lower QF expenses and lower estimated undercollections in the energy cost and electric revenue balancing accounts.

In December 1995, the CPUC approved an increase in gas revenues for PG&E of approximately $60 million in addition to the changes resulting from the GRC and other gas proceedings discussed above. The revenue increase reflects an increase in transportation costs and the collection of amounts previously deferred in balancing accounts. This decision also ordered a one-time refund, to be made during the first half of 1996, of approximately $162 million, which represents an overcollection in certain gas procurement balancing accounts.

In its November 1995 decision, the CPUC adopted the following 1996 cost of capital for PG&E:

	Capital Ratio	Cost/Return	Weighted Cost/Return
Common equity	48.00%	11.60%	5.57%
Long-term debt	46.50%	7.52%	3.49%
Preferred stock and preferred securities	5.50%	7.79%	0.43%
Total return on average utility rate base			9.49%

The revenue decrease as a result of this decision has been reflected in the GRC revenue decreases discussed above.

Diversified Operations: The Company, through its wholly owned subsidiary, Enterprises, has taken steps to position itself to compete in the nonregulated energy business. Enterprises contributed $.03, $.01 and $.04 per common share to the Company's total earnings per common share for the years ended December 31, 1995, 1994 and 1993, respectively.

Enterprises in partnership with Bechtel Enterprises, Inc. (Bechtel) has made the majority of its investments in nonregulated energy projects through a joint venture, U.S. Generating Company (USGen). USGen and its affiliates develop, own and operate power plants in the United States. As the utility business continues to change, Enterprises is pursuing emerging opportunities, including electric and gas transmission and distribution opportunities throughout the world. In 1995, Enterprises in partnership with Bechtel formed another joint venture, International Generating Company, Ltd. (InterGen). InterGen and its affiliates develop, own and operate international electric generation projects. Also, Enterprises formed Vantus Energy Corporation to assist customers outside of PG&E's service territory to locate the most cost-effective electric and gas products and services.

In June 1995, Enterprises completed its sale of DALEN Corporation (DALEN), formerly DALEN Resources. 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.

In August 1994, Enterprises and Bechtel acquired J. Makowski Company, Inc. (JMC), a Boston-based company engaged primarily in the development of natural gas-fueled electric generation projects. The purchase price was approximately $250 million. Enterprises' effective ownership share of JMC is approximately 90 percent.

Results of Operations

The Company's revenues are derived from three types of operations: utility (excluding Diablo Canyon and including PGT), Diablo Canyon and diversified operations (principally

Enterprises). The results of operations for these areas for 1995, 1994 and 1993 are reflected in the following table and discussed below.

(In millions, except per share amounts)	Utility	Diablo Canyon(1)	Diversified Operations	Total
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
1993				
Operating revenues	$ 8,366	$1,933	$ 251	$10,550
Operating expenses	6,921	810	259	7,990
Operating income (loss) before income taxes	$ 1,445	$1,123	$ (8)	$ 2,560
Net income	$ 524	$ 496	$ 45(2)	$ 1,065
Earnings per common share	$ 1.12	$ 1.11	$ .10	$ 2.33
Total assets at year end	$19,843	$6,250	$1,053	$27,146

(1) See Note 4 of Notes to Consolidated Financial Statements for discussion of allocations.
(2) Includes nonoperating income resulting from property sales, partnership earnings and investment income.

Earnings Per Common Share: Earnings per common share were $2.99, $2.21 and $2.33 for 1995, 1994 and 1993, respectively. Earnings per common share for 1995 were higher than 1994 due to fewer one-time charges against earnings than in 1994. In addition, there was only one scheduled refueling outage at Diablo Canyon in 1995, compared with two in 1994.

Earnings per common share for 1994 were lower than for 1993 primarily due to the refueling of both units of Diablo Canyon in 1994 compared to only one unit in 1993. In 1994, the Company recorded charges for workforce reductions, gas reasonableness matters, contingencies related to gas transportation commitments and increased litigation reserves which in the aggregate equaled approximately $.60 per common share. Similar charges and the impact of increasing the federal income tax rate to 35 percent in 1993 equaled, in the aggregate, approximately $.61 per common share. Partially offsetting the 1993 charges was a gain of $.05 per common share from diversified operations resulting from the sale of an investment held by Mission Trail Insurance Ltd.

On a consolidated basis, the Company earned 14.6 percent, 11.1 percent and 11.9 percent returns on average common stock equity for the years ended December 31, 1995, 1994 and 1993, respectively.

Common Stock Dividend: In January 1996, the Board declared a quarterly dividend of $.49 per common share which corresponds to an annualized dividend of $1.96 per common share. PG&E's common stock dividend is based on a number of financial considerations, including sustainability, financial flexibility and competitiveness with investment opportunities of similar risk. PG&E has a long-term objective of reducing its dividend payout ratio (dividends declared divided by earnings available for common stock) to reflect the increased business risk in the utility industry.

At this time, the Company is unable to determine the impact, if any, changes in regulation will have on its dividend level in the future.

Operating Revenues: Electric utility revenues decreased $635 million in 1995 compared to the preceding year primarily due to the decrease in electric energy costs caused by favorable hydro conditions and lower natural gas prices. In addition, Diablo Canyon operating revenues decreased due to a decrease in the price per kWh as provided in the modified pricing provisions of the Diablo Settlement. This decrease was partially offset by favorable operating revenues from Diablo Canyon resulting from fewer refueling days in 1995.

Electric utility revenues increased $145 million in 1994 as compared to the preceding year. Despite the rate freeze, electric utility revenues increased due to higher energy costs in 1994 reflected in increased electric energy cost balancing account revenues. The higher revenues from the energy cost balancing account were offset by a decrease in revenues from Diablo Canyon resulting from the refueling of both units of the nuclear power plant in 1994 as compared with only one unit in 1993.

The Diablo Settlement, which became effective July 1988, bases revenues for Diablo Canyon primarily on the amount of electricity generated, rather than on traditional cost-based ratemaking. Under this performance-based approach, the Company assumes a significant portion of the operating risk of Diablo Canyon because the extent and timing of the recovery of actual operating costs, depreciation and a return on the investment in Diablo Canyon primarily depend on the amount of power produced and the level of costs incurred.

As discussed further in Note 4 of Notes to Consolidated Financial Statements, the CPUC approved a modification to the Diablo Settlement under which the price for power produced by Diablo Canyon was reduced from the level originally set in 1988. PG&E has the right to reduce the price below the amount specified. All other terms and conditions of the Diablo Settlement remain unchanged.

Under the modified pricing, each Diablo Canyon operating unit will contribute approximately $2.7 million in revenues per day at full operating power in 1996.

The Diablo Canyon capacity factors for 1995, 1994 and 1993 were 86 percent, 81 percent and 89 percent, respectively, reflecting the refueling outages for Unit 1 in 1995, Units 1 and 2 in 1994 and Unit 2 in 1993. Through December 31, 1995, the lifetime capacity factor for Diablo Canyon was 80 percent. Because of the nature of the Diablo Settlement, the Company will report significantly lower revenues for Diablo Canyon during any extended outages, including refueling outages. In the past, refueling outages, the length of which depend on the scope of the work, typically occurred for each unit every 18 months. Beginning in 1996, refueling outages will be planned every 21 months as allowed under Diablo Canyon's current NRC operating license. PG&E intends to seek licensing authority from the NRC to extend the time between refueling outages to 24 months beginning in 2001. The next refueling outages for Unit 1 and Unit 2 are scheduled to begin in May 1997 and April 1996, respectively, and each is planned to last approximately six weeks.

Gas utility revenues decreased $341 million in 1994 as compared to the preceding year primarily due to a decrease in revenues received from noncore customers, who are now arranging for the purchase of their own gas supplies, with PG&E providing transportation service only. This decrease was partially offset by higher revenues generated from the Pipeline Expansion. (See Note 3 of Notes to Consolidated Financial Statements for further discussion.)

Revenues from diversified operations decreased $71 million in 1995 compared to the preceding year primarily due to the sale of DALEN in June 1995. (See the Diversified Operations section above for further discussion.)

Operating Expenses: Operating expenses decreased $1,068 million in 1995 as compared to the preceding year primarily due to decreased electric costs caused by favorable hydro conditions, decreased natural gas prices and no workforce reduction charges in 1995. (See Note 10 of Notes to Consolidated Financial Statements.)

Operating expenses in 1994 remained constant as compared to 1993. The 1994 and 1993 operating expenses included workforce reduction charges against earnings of $249 million and $190 million, respectively. The cost of electric energy was $321 million greater in 1994, primarily due to less favorable hydro conditions and an increase in the cost of purchased power. These unfavorable 1994 variances were offset by a favorable variance of $369 million in the cost of gas as a result of PG&E no longer procuring gas for certain customers.

Budgeted 1996 operating expenses are approximately $250 million greater than the amount adopted by the CPUC for setting rates in the 1996 GRC. The greater expense level is primarily attributable to several projects related to distribution system reliability, improved customer service and public information systems. To the extent that additional cost reductions do not offset the greater expense level, PG&E's authorized return on equity will be adversely impacted.

Liquidity and Capital Resources

Sources of Capital: The Company's capital requirements are funded from cash provided by 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. Proceeds from the issuance of securities are used for capital expenditures, refundings and other general corporate purposes.

Debt: In 1995, PG&E issued no debt, while PGT issued $400 million of bonds and $70 million of medium-term notes. All other debt issued during the year by PGT was commercial paper, which is classified as long-term debt and which had a balance outstanding at December 31, 1995, of $109 million. Substantially all of the proceeds of PGT's debt issued were used to refinance outstanding PGT debt. Also in 1995, PG&E redeemed or repurchased $114 million of mortgage bonds in an effort to reduce the levels of higher-cost debt.

In 1994, PG&E issued $30 million of medium-term notes and redeemed or repurchased $135 million of mortgage bonds, medium-term notes and Eurobonds. In 1993, PG&E issued $4 billion of mortgage bonds, pollution control revenue bonds and medium-term notes. Substantially all these proceeds were used to redeem or repurchase higher-cost mortgage bonds to accomplish a reduction in financing costs.

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, 1995 and 1994, PG&E had $796 million and $525 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 also can be used for general corporate purposes. There were no borrowings under this facility in 1995, 1994 or 1993.

Equity: In 1995 and 1994, PG&E received $140 million 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. Proceeds were used for capital expenditures and other general corporate purposes.

In 1993, the Board authorized PG&E to reinstate its common stock repurchase program. Since that time, the Board has authorized PG&E to repurchase up to $2 billion of its common stock on the open market or in negotiated transactions. This program is funded by internally generated funds. Shares are being repurchased to manage the overall balance of common stock in PG&E's capital structure. Through December 31, 1995, PG&E had repurchased approximately $1 billion of its common stock under this program.

In 1994 and 1993, PG&E issued $62 million and $200 million, respectively, of preferred stock. In 1995, 1994 and 1993, PG&E redeemed or repurchased $331 million, $75 million and $267 million, respectively, of its higher-cost preferred stock.

Other Capital: In 1995, PG&E through its wholly owned subsidiary, PG&E Capital I, issued $300 million of cumulative quarterly income preferred securities.

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

Year ended December 31, (in millions)	1996	1997	1998
Utility	$1,291	$1,220	$1,283
Diablo Canyon	36	37	39
Diversified operations	162	153	332
Total capital expenditures	1,489	1,410	1,654
Maturing debt and sinking funds	304	322	668
Total capital requirements	$1,793	$1,732	$2,322

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.

Diversified operations consist substantially of Enterprises whose estimated expenditures include project development expenditures for power and real estate projects and equity commitments associated with generating facility projects.

In addition to these capital requirements, the Company has other commitments as discussed in Notes 3 and 12 of Notes to Consolidated Financial Statements.

New Accounting Standard: The Company will adopt SFAS No. 121 effective January 1, 1996. The general provisions of SFAS No. 121 require, among other things, that the existence of an impairment be evaluated whenever events or changes in circumstances indicate that the carrying amount of an asset may not be fully recoverable and prescribe standards for the recognition and measurement of impairment losses. In addition, SFAS No. 121 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.

Based on the expected CTC recovery set forth in the CPUC decision on electric industry restructuring discussed in Note 2 of Notes to Consolidated Financial Statements, the Company currently does not anticipate a material impairment of its assets. However, the CPUC decision is subject to legislative review. Should final regulations differ significantly from the CPUC decision or should full recovery of generation assets and obligations not be achieved due to changing costs or limitations imposed by the market, a material loss could occur.

Risk Management: Due to the changing regulatory environment, the Company's exposure to price risk is expected to increase. To manage this risk, in December 1995, the Company adopted a risk management policy and created a committee of officers to oversee the implementation of the policy, approve each price risk management program and monitor compliance with the policy.

This action established policies and guidelines for cost effective risk management programs designed to mitigate financial exposure to changes in the price of energy commodities, interest rates and currencies. These programs may include the use of financial derivatives that are designed to offset changes in the value of an underlying asset, obligation, instrument, contract or index on a one-for-one basis. This policy prohibits the use of financial derivatives whose payment formula includes a multiple of some underlying asset. It also prohibits engaging in speculative financial derivatives trading or adopting compensation policies that encourage such speculative trading. The Company had no open positions in derivative financial instruments at December 31, 1995.

The Company also uses other techniques to manage its financial risk including the purchase of commercial insurance and the maintenance of systems of internal control. The extent to which these techniques are used depends on the risk of loss and the cost to employ such techniques.

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 $65 million, $68 million and $121 million for 1996, 1997 and 1998, respectively. Expenditures during these years will be primarily for nitrogen oxide (NOx) emission reduction projects for the Company's fossil fuel fired 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 from company facilities. Final rules have yet to be adopted in all local air districts in which PG&E operates and these rules continue to be modified. The Company currently estimates that compliance with NOx rules likely to be in place could require capital expenditures of up to $415 million over the next ten years.

The Company assesses, on an ongoing basis, measures that may need to be taken to comply with laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Company has an accrued liability at December 31, 1995, of $122 million for hazardous waste remediation costs at those sites where such costs are probable and quantifiable. The costs may be as much as $287 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, among 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. (See Note 13 of Notes to Consolidated Financial Statements.)

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 impact on either the Company's results of operations or financial position.

Significant litigation cases are discussed in Note 13 of Notes to Consolidated Financial Statements. These cases involve claims for personal injury, and property and punitive damages allegedly suffered as a result of exposure to chromium near PG&E's Hinkley Compressor Station; antitrust claims for damages as a result of Canadian natural gas purchases by one of the Company's wholly owned subsidiaries and a claim that PG&E underpaid franchise fees.

Accounting for Decommissioning Expense: The staff of the Securities and Exchange Commission has questioned certain current accounting practices of the electric utility industry, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board has agreed to review the accounting for closure and removal costs, including decommissioning of nuclear power plants. If current electric utility industry accounting practices for such decommissioning are changed: (1) annual expense for decommissioning could increase and (2) the estimated total cost for decommissioning could be recorded as a liability rather than accrued over time as accumulated depreciation, with recognition of an increase in the cost of the related nuclear power plant. The Company does not believe that such changes, if required, would have an adverse effect on its results of operations due to its current and future ability to recover decommissioning costs through rates. (See Note 2 of Notes to Consolidated Financial Statements for discussion of electric industry restructuring.)

Statement of Consolidated Income

Year ended December 31, (In thousands, except per share amounts)	1995	1994	1993
Operating Revenues			
Electric utility	$7,386,307	$ 8,021,547	$ 7,876,925
Gas utility	2,059,117	2,081,062	2,421,733
Diversified operations	176,341	247,621	251,344
Total operating revenues	9,621,765	10,350,230	10,550,002
Operating Expenses			
Cost of electric energy	2,116,840	2,570,723	2,250,209
Cost of gas	333,280	583,356	952,510
Maintenance and other operating	1,799,781	1,855,585	1,942,376
Depreciation and decommissioning	1,360,118	1,397,470	1,315,524
Administrative and general	971,576	973,302	1,041,453
Workforce reduction costs	(18,195)	249,097	190,200
Property and other taxes	295,380	296,911	297,495
Total operating expenses	6,858,780	7,926,444	7,989,767
Operating Income	2,762,985	2,423,786	2,560,235
Other Income and (Income Deductions)			
Interest income	72,524	79,643	55,361
Allowance for equity funds used during construction	20,039	19,046	41,531
Other—net	58,564	37,996	51,061
Total other income and (income deductions)	151,127	136,685	147,953
Income Before Interest Expense	2,914,112	2,560,471	2,708,188
Interest Expense			
Interest on long-term debt	629,548	651,912	731,610
Other interest charges	61,033	77,295	87,819
Allowance for borrowed funds used during construction	(10,643)	(12,953)	(78,626)
Total interest expense	679,938	716,254	740,803
Pretax Income	2,234,174	1,844,217	1,967,385
Income Taxes	895,289	836,767	901,890
Net Income	1,338,885	1,007,450	1,065,495
Preferred dividend requirement and redemption premium	70,288	57,603	63,812
Earnings Available for Common Stock	$1,268,597	$ 949,847	$ 1,001,683
Weighted Average Common Shares Outstanding	423,692	429,846	430,625
Earnings Per Common Share	$ 2.99	$ 2.21	$ 2.33
Dividends Declared Per Common Share	$ 1.96	$ 1.96	$ 1.88

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

Consolidated Balance Sheet

December 31, (in thousands)	1995	1994
Assets		
Plant In Service		
Electric		
Nonnuclear	$17,513,830	$17,045,247
Diablo Canyon	6,646,853	6,647,162
Gas	7,732,681	7,447,879
Total plant in service (at original cost)	31,893,364	31,140,288
Accumulated depreciation and decommissioning	(13,308,596)	(12,269,377)
Net plant in service	18,584,768	18,870,911
Construction Work In Progress	333,263	527,867
Other Noncurrent Assets		
Oil and gas properties	—	437,352
Nuclear decommissioning funds	769,829	616,637
Investment in nonregulated projects	869,674	761,355
Other assets	130,128	137,325
Total other noncurrent assets	1,769,631	1,952,669
Current Assets		
Cash and cash equivalents	734,295	136,900
Accounts receivable		
Customers	1,238,549	1,413,185
Other	65,907	98,035
Allowance for uncollectible accounts	(35,520)	(29,769)
Regulatory balancing accounts receivable	746,344	1,245,100
Inventories		
Materials and supplies	181,763	197,394
Gas stored underground	146,499	136,326
Fuel oil	40,756	67,707
Nuclear fuel	175,957	140,357
Prepayments	47,025	33,251
Total current assets	3,341,575	3,438,486
Deferred Charges		
Income tax-related deferred charges	1,079,673	1,155,421
Diablo Canyon costs	382,445	401,110
Unamortized loss net of gain on reacquired debt	392,116	382,862
Workers' compensation and disability claims recoverable	297,266	247,209
Other	669,553	732,029
Total deferred charges	2,821,053	2,918,631
Total Assets	$26,850,290	$27,708,564

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

Consolidated Balance Sheet

December 31, (In thousands)	1995	1994
Capitalization and Liabilities		
Capitalization		
Common stock	$ 2,070,128	$ 2,151,213
Additional paid-in capital	3,716,322	3,806,508
Reinvested earnings	2,812,683	2,677,304
Total common stock equity	8,599,133	8,635,025
Preferred stock without mandatory redemption provision	402,056	732,995
Preferred stock with mandatory redemption provision	137,500	137,500
Company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures	300,000	—
Long-term debt	8,048,546	8,675,091
Total capitalization	17,487,235	18,180,611
Other Noncurrent Liabilities		
Customer advances for construction	146,191	152,384
Workers' compensation and disability claims	271,000	221,200
Other	815,960	819,893
Total other noncurrent liabilities	1,233,151	1,193,477
Current Liabilities		
Short-term borrowings	829,947	524,685
Long-term debt	304,204	477,047
Accounts payable		
Trade creditors	413,972	414,291
Other	387,747	337,726
Accrued taxes	274,093	436,467
Deferred income taxes	227,782	432,026
Interest payable	70,179	84,805
Dividends payable	205,467	210,903
Other	504,973	468,119
Total current liabilities	3,218,364	3,386,069
Deferred Credits		
Deferred income taxes	3,933,765	3,902,645
Deferred tax credits	393,255	391,455
Noncurrent balancing account liabilities	185,647	226,844
Other	398,873	427,463
Total deferred credits	4,911,540	4,948,407
Commitments and Contingencies (Notes 1, 2, 3, 12 and 13)		
Total Capitalization and Liabilities	$26,850,290	$27,708,564

Statement of Consolidated Cash Flows

Year ended December 31, (In thousands)	1995	1994	1993
Cash Flows From Operating Activities			
Net income	$ 1,338,885	$ 1,007,450	$ 1,065,495
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and decommissioning	1,360,118	1,397,470	1,315,524
Amortization	89,353	95,331	135,808
Gain on sale of DALEN	(13,107)	—	—
Deferred income taxes and tax credits—net	(116,069)	15,312	319,198
Allowance for equity funds used during construction	(20,039)	(19,046)	(41,531)
Other deferred charges	61,700	32,740	(158,725)
Other noncurrent liabilities	(17,218)	181,902	50,279
Noncurrent balancing account liabilities and other deferred credits	(69,787)	316,920	124,189
Net effect of changes in operating assets and liabilities			
Accounts receivable	212,515	(116,936)	64,790
Regulatory balancing accounts receivable	498,756	(269,250)	(232,597)
Inventories	32,409	66,783	23,097
Accounts payable	49,702	(110,033)	(39,422)
Accrued taxes	(162,374)	132,892	44,638
Other working capital	8,304	5,821	108,873
Other—net	83,569	210,331	13,184
Net cash provided by operating activities	3,336,717	2,947,687	2,792,800
Cash Flows From Investing Activities			
Capital expenditures	(931,908)	(1,094,495)	(1,763,024)
Allowance for borrowed funds used during construction	(10,643)	(12,953)	(78,626)
Diversified operations	(180,941)	(328,266)	(234,221)
Proceeds from sale of DALEN	340,000	—	—
Other—net	(122,913)	(29,914)	9,992
Net cash used by investing activities	(906,405)	(1,465,628)	(2,065,879)
Cash Flows From Financing Activities			
Common stock issued	139,595	274,269	264,489
Common stock repurchased	(601,360)	(181,558)	(257,780)
Preferred stock issued	—	62,312	200,001
Preferred stock redeemed or repurchased	(358,212)	(82,875)	(302,640)
Company obligated mandatorily redeemable preferred securities issued	300,000	—	—
Long-term debt issued	591,160	60,907	4,584,548
Long-term debt matured, redeemed or repurchased	(1,296,549)	(436,673)	(4,002,704)
Short-term debt issued (redeemed)—net	305,262	(239,478)	(366,961)
Dividends paid	(891,270)	(891,850)	(857,515)
Other—net	(21,543)	28,721	(24,885)
Net cash used by financing activities	(1,832,917)	(1,406,225)	(763,447)
Net Change in Cash and Cash Equivalents	597,395	75,834	(36,526)
Cash and Cash Equivalents at January 1	136,900	61,066	97,592
Cash and Cash Equivalents at December 31	$ 734,295	$ 136,900	$ 61,066
Supplemental disclosures of cash flow information			
Cash paid for			
Interest (net of amounts capitalized)	$ 647,151	$ 674,758	$ 642,712
Income taxes	1,125,635	712,777	542,827

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

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 Provision	Preferred Stock With Mandatory Redemption Provision[1]
Balance December 31, 1992	$2,134,228	$3,517,062	$2,631,847	$8,283,137	$790,791	$159,510
Net income—1993			1,065,495	1,065,495		
Common stock issued (7,708,512 shares)	38,541	225,948		264,489		
Common stock repurchased (7,334,876 shares)	(36,674)	(63,180)	(157,926)	(257,780)		
Preferred stock issued (8,000,000 shares)					200,001	
Preferred stock redeemed (8,156,968 shares)		(13,375)	(21,958)	(35,333)	(182,797)	(84,510)
Cash dividends declared						
Preferred stock			(62,521)	(62,521)		
Common stock			(811,196)	(811,196)		
Other			(254)	(254)		
Net change	1,867	149,393	11,640	162,900	17,204	(84,510)
Balance December 31, 1993	2,136,095	3,666,455	2,643,487	8,446,037	807,995	75,000
Net income—1994			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)		
Net change	15,118	140,053	33,817	188,988	(75,000)	62,500
Balance December 31, 1994	2,151,213	3,806,508	2,677,304	8,635,025	732,995	137,500
Net income—1995			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 securites issued[2] (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		
Net change	(81,085)	(90,186)	135,379	(35,892)	(330,939)	300,000
Balance December 31, 1995	$2,070,128	$3,716,322	$2,812,683	$8,599,133	$402,056	$437,500

(1) Includes current portion.
(2) Relates to company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures.

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

Statement of Consolidated Capitalization

December 31, (dollars in thousands, except per share amounts)	1995	1994
Common Stock Equity		
Common stock, par value $5 per share (authorized 800,000,000 shares, issued and outstanding 414,025,586 and 430,242,687)	$ 2,070,128	$ 2,151,213
Additional paid-in capital	3,716,322	3,806,508
Reinvested earnings	2,812,683	2,677,304
Common stock equity	8,599,133	8,635,025
Preferred Stock and Preferred Securities		
Preferred stock without mandatory redemption provision		
Par value $25 per share[1]		
Nonredeemable		
5% to 6%—5,784,825 shares outstanding	144,621	144,621
Redeemable		
4.36% to 8.20%—10,297,404 and 23,534,958 shares outstanding	257,435	588,374
Total preferred stock without mandatory redemption provision	402,056	732,995
Preferred stock with mandatory redemption provision		
Par value $25 per share[1]		
6.30% to 6.57%—5,500,000 shares outstanding	137,500	137,500
Par value $100 per share (authorized 10,000,000 shares)	—	—
Total preferred stock with mandatory redemption provision	137,500	137,500
Preferred stock	539,556	870,495
Company obligated mandatorily redeemable preferred securities of trust holding solely PG&E subordinated debentures 7.90%—12,000,000 shares outstanding	300,000	—
Long-term Debt		
PG&E long-term debt		
First and refunding mortgage bonds		
Maturity — Interest rates		
1995–2000 — 4.25% to 6.875%	816,249	823,823
2001–2005 — 5.875% to 8.75%	1,549,000	1,549,000
2006–2012 — 6.25% to 8.875%	477,870	477,870
2013–2019 — 7.5% to 12.75%	105,000	136,030
2020–2026 — 5.85% to 9.30%	2,749,651	2,902,945
Principal amounts outstanding	5,697,770	5,889,668
Unamortized discount net of premium	(55,802)	(66,198)
Total mortgage bonds	5,641,968	5,823,470
Debentures, 10.81% to 12%, due 1995–2000	57,539	124,939
Pollution control loan agreements, variable rates, due 2008–2016	925,000	925,000
Unsecured medium-term notes, 4.13% to 9.9%, due 1995–2014	1,096,400	1,443,800
Unamortized discount related to unsecured medium-term notes	(1,652)	(2,428)
Other long-term debt	20,298	22,209
Total PG&E long-term debt	7,739,553	8,336,990
Long-term debt of subsidiaries	613,197	815,148
Total long-term debt of PG&E and subsidiaries	8,352,750	9,152,138
Less long-term debt—current portion	304,204	477,047
Long-term debt	8,048,546	8,675,091
Total Capitalization	$17,487,235	$18,180,611

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

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

Schedule of Consolidated Segment Information

(In thousands)	Electric Utility	Gas Utility	Diversified Operations[4]	Intersegment Eliminations	Total
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	—	—	962,590
Identifiable assets[3]	$18,402,373	$6,272,833	$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	—	—	1,126,494
Identifiable assets[3]	$19,464,080	$6,340,456	$1,436,128	$ —	$27,240,664
Corporate assets					467,900
Total assets at year end					$27,708,564
1993					
Operating revenues	$ 7,876,925	$2,421,733	$ 251,344	$ —	$10,550,002
Intersegment revenues[1]	15,369	223,443	—	(238,812)	—
Total operating revenues	$ 7,892,294	$2,645,176	$ 251,344	$(238,812)	$10,550,002
Depreciation and decommissioning	$ 925,673	$ 251,490	$ 138,361	$ —	$ 1,315,524
Operating income before income taxes[2]	2,328,241	247,846	(7,812)	(8,040)	2,560,235
Capital expenditures[3]	929,065	954,116	—	—	1,883,181
Identifiable assets[3]	$19,124,964	$6,451,388	$1,053,027	$ —	$26,629,379
Corporate assets					516,520
Total assets at year end					$27,145,899

(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 Pacific Gas Properites Company (real estate development).

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

Note 1: Summary of Significant Accounting Policies

Pacific Gas and Electric Company (PG&E) and its wholly owned and controlled subsidiaries (collectively, the Company) are engaged principally in the business of supplying electric and natural gas 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. A significant component of PG&E's electric generation is its operation of the Diablo Canyon Nuclear Power Plant (Diablo Canyon), as discussed in Note 4. PG&E's diversified operations, conducted primarily through its wholly owned subsidiary, PG&E Enterprises (Enterprises), include non-utility electric generation and power plant operations and services.

Major subsidiaries, all of which are wholly owned, are Pacific Gas Transmission Company (PGT) — an interstate pipeline company that transports natural gas from the U.S./Canadian border to the California border and Enterprises — the parent company for substantially all of PG&E's diversified operations, including PG&E Generating Company which through a joint venture (U.S. Generating Company) develops, owns and operates power plants. DALEN Corporation, a wholly owned subsidiary of Enterprises engaged in exploration, development and production of oil and natural gas, was sold in June 1995.

The consolidated financial statements include PG&E and its wholly owned and controlled subsidiaries. All significant intercompany transactions have been eliminated. Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the 1995 presentation.

Regulation: The operations of the utility and Diablo Canyon are regulated by the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC) and the Nuclear Regulatory Commission, among others. The consolidated financial statements reflect the ratemaking policies of the CPUC and the FERC in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-of-service based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, certain costs are deferred as regulatory assets when recovery through rates is not currently provided but is expected in the future. As a result of applying the provisions of SFAS No. 71, PG&E has accumulated approximately $3.2 billion of net regulatory assets, including balancing accounts, at December 31, 1995.

The CPUC has established mechanisms known as balancing accounts which help stabilize PG&E's earnings. 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 these balancing accounts is subject to a reasonableness review by the CPUC. (See Note 3 for further discussion of gas costs.)

Plant in Service: The cost of plant additions and replacements is capitalized. Cost includes labor, materials, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of debt and equity funds used to finance the construction of new facilities. Financing costs of capital additions for Diablo Canyon, the PG&E portion of the PGT/PG&E Pipeline

Expansion Project (Pipeline Expansion) and other non-regulated projects are calculated in accordance with SFAS No. 34, "Capitalization of Interest Cost." The original cost of retired plant plus removal costs less salvage value are charged to accumulated depreciation. Maintenance, repairs and minor replacements and additions are charged to maintenance expense.

Depreciation and Nuclear Decommissioning Costs: Depreciation of plant in service is computed using a straight-line remaining-life method.

The estimated cost of decommissioning PG&E's nuclear power facilities is recovered in base rates through an annual allowance. For the years ended December 31, 1995, 1994 and 1993, the amount recovered in rates for decommissioning costs was $54 million each year. Based on a 1994 site study of decommissioning costs, the amount to be recovered in rates in 1996 will be $36 million. It is assumed that this amount will be recovered annually in rates up to the commencement of decommissioning. However, this amount will again be reviewed in PG&E's future rate proceedings. Also, based on this study, the estimated total obligation for nuclear decommissioning costs is approximately $1.2 billion in 1995 dollars (or $5.9 billion in future dollars, an increase of $1.4 billion from the 1991 site study resulting primarily from lengthening the decommissioning period); this obligation is being recognized ratably over the facilities' lives. The decommissioning period for Diablo Canyon Unit 1 is 2015 through 2034 and 2016 through 2034 for Diablo Canyon Unit 2. This estimate considers the total cost (including labor, materials and other costs) of decommissioning and dismantling plant systems and structures and includes a contingency factor for possible changes in regulatory requirements and waste disposal cost increases. The average annualized escalation rate and the assumed after-tax annualized rate of return on qualified trust assets used to calculate the decommissioning obligation and annual expense are 6.00 percent and 6.20 percent (5.75 percent on nonqualified trust assets), respectively. (See Note 8 for further discussion of nuclear decommissioning funds.) The actual decommissioning costs are expected to vary from the above estimates because of changes in assumed dates of decommissioning, regulatory requirements, technology and costs of labor, materials and equipment.

The decommissioning method selected for Diablo Canyon anticipates that the equipment, structures and portions of the facility and site containing radioactive contaminants will be removed or decontaminated to a level that permits the property to be released for unrestricted use. Humboldt Bay Power Plant is being decommissioned under a method that consists of placing and maintaining the facility in protective storage until some future time when dismantling can be initiated.

As required by federal law, the U.S. Department of Energy (DOE) is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. PG&E, as required by federal law, has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from its nuclear generation stations beginning not later than January 1998; however, this delivery schedule is expected to be delayed. It is not certain when the DOE will accept high-level radioactive waste from PG&E and other owners of nuclear power plants. Extended delays or a default by the DOE would lead to consideration of costly alternatives involving serious siting and environmental issues. PG&E pays a one-tenth of one cent fee on each nuclear kilowatt-hour (kWh) sold to fund DOE storage and disposal activities. PG&E has primary responsibility for the interim storage of its spent nuclear fuel.

Gains and Losses on Reacquired Debt: Gains and losses on reacquired debt charged to the utility are amortized over the remaining original lives of the debt reacquired, consistent with ratemaking treatment. Gains and losses on reacquired debt charged to Diablo Canyon and the PG&E portion of the Pipeline Expansion are recognized in income at the time such debt is reacquired.

Inventories: Nuclear fuel inventory is stated at the lower of average cost or market. Amortization of nuclear fuel in the reactor is 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.

Statement of Consolidated Cash Flows: Cash and cash equivalents (valued at cost which approximates market) include special deposits, working funds and short-term investments with original maturities of three months or less.

Use of Estimates: The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

New Accounting Standard: SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," effective January 1, 1996, 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.

Based on the expected competition transition charge (CTC) recovery set forth in the CPUC decision on electric industry restructuring discussed in Note 2, the Company currently does not anticipate a material impairment of its assets and, specifically, its generation-related regulatory assets and investments in electric generation assets. However, the CPUC decision is subject to legislative review. Should final regulations differ significantly from the CPUC decision or should full recovery of generation assets and obligations not be achieved due to changing costs or limitations imposed by the market, a material loss could occur.

Note 2: Electric Industry Restructuring

On December 20, 1995, the CPUC issued a decision calling for the restructuring of California's electric industry. The CPUC's goal is to provide a structure that will ultimately allow California consumers to choose among competing suppliers of electricity. In summary, the decision would (1) simultaneously create a wholesale power pool (the Exchange) and allow direct access for certain customers to contract directly with electric generation providers beginning in 1998 with all customers phased in within five years; (2) establish an Independent System Operator (ISO) to manage and control the transmission system; and (3) provide recovery of utilities' stranded costs (costs which are above-market and could not be recovered under market-based pricing) through a surcharge, or CTC, to be imposed on all customers. The decision, while effective immediately, provides a 100-day period for legislative review.

Under the restructuring decision, PG&E would continue to provide distribution, generation and procurement functions for those customers choosing to take bundled service, all of which would be regulated under performance-based ratemaking. The decision requires PG&E to file proposals to establish performance-based ratemaking for its generation and distribution functions.

The CPUC concluded that market power issues associated with the electric industry restructuring almost certainly mandate that the investor-owned utilities (IOUs) divest themselves of a substantial portion of their fossil fuel generation assets. Accordingly, the decision requires PG&E to file a plan to voluntarily divest itself of at least 50 percent of its fossil fuel generation assets.

The decision provides for the collection of transition costs through the imposition of a non-bypassable CTC. Transition cost recovery shall not increase rates beyond the rate levels in effect as of January 1, 1996. A transition cost account will be established for each utility. Transition costs associated with regulatory assets will be included in the account as authorized by the CPUC. The account will be adjusted annually for the difference between authorized revenues associated with the generation assets and actual revenues earned in the market as well as after a generation asset receives its market valuation. Valuation of above-market generation assets will be completed by 2003. Utility nonnuclear generation assets will be valued through sale, spin-off or market appraisal.

Transition costs resulting from the operation of nuclear generation facilities and electricity purchases under existing wholesale and qualifying facility (QF) contracts will also be recorded in this account. Transition costs for these resources will be calculated annually over the terms of the contracts or until the authorized transition cost recovery has been completed. Except for existing QF generation contracts with contractual payments beyond 2003, all transition costs will be collected by 2005.

With respect to recovery of costs associated with Diablo Canyon and the Diablo Canyon rate case settlement (Diablo Settlement), the decision confirms that the CPUC will continue to honor regulatory commitments regarding the recovery of nuclear generation costs. Diablo Canyon transition costs will be calculated over the term of the Diablo Settlement. The decision requires PG&E to file a proposal for pricing Diablo Canyon generation at market prices by 2003 and for completing recovery of Diablo Canyon CTC by 2005 while assuring no overall rate increase over January 1, 1996, levels. If PG&E retains ownership of Diablo Canyon, decommissioning costs will also be included in the transition cost account.

Financial Impact of the Electric Industry Restructuring: In December 1994, in response to one of the proceedings leading to the decision, PG&E estimated the revenue requirements of its owned generation assets and power purchase obligations to be above market by $3 billion and $11 billion at assumed market prices of $.040 and $.032 per kWh, respectively. These market prices were used to provide a range of possible transition costs and do not represent a forecast of expected market prices. These above-market estimates were determined by comparing future revenue requirements of generation assets and power purchase obligations, over a 20-year and 30-year period, respectively, with revenues computed at assumed market prices. The revenue requirements for Diablo Canyon and all PG&E-owned generation assets included a return on investment. Diablo Canyon was included in the revenue requirements calculation using the revised pricing included in the modified Diablo Settlement. (See Note 4.) The above-market revenue requirements for Diablo Canyon included above were $4 billion and $6 billion at assumed market prices of $.040 and $.032 per kWh, respectively. At this time, PG&E has not completed a more current estimate of its above-market revenue requirements. However, market prices could be less than $.032 per kWh. The actual amounts of above-market revenue requirements may differ materially from those indicated above and will depend on the final regulations and the actual market prices of electricity or a definitive market valuation.

The CPUC electric industry restructuring decision establishes an account to track the accumulation of transition costs and their recovery. While the decision provides an opportunity for recovery of all above-market costs, actual recovery will occur through a CTC applied to transmission and distribution rates. The level of CTC will be limited to an amount that does not increase the customers' aggregate rates above those in effect January 1, 1996. Recent CPUC decisions effective on January 1, 1996, including PG&E's General Rate Case (GRC), have resulted in an average electric system rate of 9.9 cents per kWh. PG&E's ability to recover its transition costs will be dependent on achieving overall reductions in costs such that it can recover its ongoing operating costs, capital costs and transition costs at the 1996 rate level and on continuing to collect CTC for the duration of the recovery period.

As a result of applying the provisions of SFAS No. 71 (see Note 1), PG&E has accumulated approximately $2.6 billion of electric regulatory assets, including balancing accounts, at December 31, 1995. The regulatory assets attributable to electric generation, excluding balancing accounts of $248 million which are expected to be recovered in the near term, were approximately $1.5 billion at December 31, 1995. When generation rates are no longer based on cost of service, as ultimately contemplated under the decision, PG&E will discontinue application of SFAS No. 71 for that portion of its business. However, PG&E expects to recover its regulatory assets as transition costs through the CTC and does not expect a material loss from the discontinuance of SFAS No. 71. PG&E's transmission and distribution businesses are expected to remain on cost-of-service rates.

In addition, the adoption of SFAS No. 121 in 1996 will require that all regulatory assets continue to be probable of recovery in rates. In the event that this criterion can no longer be met, whether due to changing regulation or PG&E's inability to collect these costs, applicable portions of any regulatory assets would be written off. The transition cost account will be a regulatory asset also subject to the criteria of SFAS No. 121.

The net book value of PG&E's investment in Diablo Canyon was approximately $4.8 billion at December 31, 1995. The net book value of the remaining PG&E-owned generation assets, including an allocation of common plant, was approximately $3.1 billion at December 31, 1995.

Because of the expected transition cost recovery as provided in the decision, PG&E does not anticipate a material impairment loss on its investment in generation assets due to electric industry restructuring. However, should final regulations differ significantly from the CPUC decision or should full recovery of generation assets and obligations not be achieved due to changing costs or limitations imposed by the market, a material loss could occur.

The Company cannot predict the ultimate outcome of the ongoing changes that are taking place in the electric utility industry or predict whether such outcome will have a material impact on its financial position or results of operations.

Note 3: Natural Gas Matters

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 decisions covering the years 1988 through 1990, ordering disallowances of approximately $90 million of gas costs, plus accrued interest of approximately $25 million through 1993 for PG&E's Canadian gas procurement activities, and $8 million for gas inventory operations. PG&E has filed a lawsuit in a federal district court challenging the CPUC decision on Canadian gas costs. In September 1995, the federal court denied a motion filed by the CPUC to dismiss the lawsuit.

During 1995, the CPUC approved settlement agreements between the CPUC's Division of Ratepayer Advocates (DRA) and PG&E which resolve $25 million of disallowances recommended by the DRA relating to certain non-Canadian gas issues arising from the 1991 and 1992 record periods. Pursuant to these agreements, PG&E will refund $1.1 million to ratepayers.

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 are still under review by the CPUC. The DRA had recommended disallowances of approximately $79 million and a penalty of $50 million and indicated that it was considering additional recommendations for pending issues. PG&E and the DRA have signed a settlement agreement to resolve these issues for a $67 million disallowance.

As of December 31, 1995, PG&E has accrued approximately $208 million for the CPUC decisions for the years 1988 through 1992 and issues covered by the settlement agreements described above. The Company believes the ultimate outcome of these matters will not have a material impact on its financial position or results of operations.

Settlement of certain other unresolved gas issues is being negotiated as part of the Gas Accord negotiations discussed below.

Pipeline Expansion: In November 1993, the Company placed in service an expansion of its natural gas transmission system from the Canadian border into California. The Pipeline Expansion provides additional firm transportation capacity to Northern and Southern California and the Pacific Northwest. The total cost of construction was approximately $1.7 billion; $813 million for the PG&E or California portion and $852 million for the PGT or interstate portion.

PG&E has filed an application with the CPUC requesting that capital and operating costs for the PG&E portion of the Pipeline Expansion be found reasonable. In that CPUC proceeding, the DRA recommended that $100 million in capital costs be disallowed for recovery in rates while two intervenors jointly recommended a $223 million disallowance. An order issued by a CPUC Administrative Law Judge (ALJ) has also reopened the 1993 PG&E Pipeline Expansion Rate Case to allow reconsideration of issues regarding the decision to construct the PG&E Pipeline Expansion.

In January 1996, a CPUC ALJ ordered consolidation of the market impact phase of the PG&E Pipeline Expansion reasonableness proceeding and the Interstate Transition Cost Surcharge (ITCS) proceeding discussed below.

If the CPUC were to reverse its previous decision finding PG&E was reasonable in constructing the PG&E Pipeline Expansion, the ultimate outcome could have an impact on PG&E's ability to recover its cost for unused capacity on other pipelines as well as on its own intrastate facilities.

For the interstate portion of the Pipeline Expansion, PGT included the total capital cost in its 1994 GRC filing with the FERC; no parties contested these costs. Decisions in these three proceedings are expected in 1996. Revenues are currently being collected under interim rates approved by the FERC and the CPUC, subject to adjustment.

Transportation Commitments: PG&E has gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for 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 and may be offset to the extent PG&E can broker or permanently assign any unused capacity. In addition to demand charges, PG&E is required to pay transportation charges for actual quantities shipped. The total demand and transportation charges paid by PG&E under these agreements (excluding agreements with PGT) were approximately $175 million in 1995, $225 million in 1994 and $280 million in 1993.

The following table summarizes the approximate capacity held by PG&E on various pipelines and the related annual demand charges as of December 31, 1995:

Pipeline Company	Firm Capacity Held (MMcf/d)	Total Annual Demand Charges (in millions)	Contract Expiration
El Paso	1,140	$163	Dec. 1997
Transwestern	200	$ 28	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 industrial and large commercial (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 its residential and smaller commercial (core) customers and noncore customers who choose bundled service (core subscription customers). In order to service 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) and Alberta Natural Gas Company Ltd (ANG).

PG&E is continuing its efforts to broker or assign any remaining unused capacity including that held for its core and core subscription customers when such capacity is not being used. 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, including charges for capacity formerly used to service noncore customers which cannot be brokered or brokered at a discount, are eligible for rate recovery, subject to a reasonableness review. However, certain groups, including the DRA and intervenors, have challenged the recovery of certain 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 subscribe for transportation capacity with Transwestern. The decision concluded that PG&E was unable to prove the benefits of such capacity during 1992 and denied recovery of the $18 million of Transwestern charges for that year. The decision further 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. PG&E is seeking rehearing of this decision.

The recovery of demand charges associated with capacity which was formerly used to service PG&E's noncore customers will be decided by the CPUC in the ITCS proceeding. Pending a final decision in the ITCS proceeding, the CPUC has approved collection in rates of approximately one-half of the demand charges for unbrokered or discounted El Paso and PGT capacity which was formerly used to service PG&E's noncore customers, subject to refund.

In October 1995, PG&E presented a proposal, called the Gas Accord, to numerous parties active in the California gas marketplace, in an effort to restructure the California gas market. As part of the Gas Accord negotiations, PG&E is pursuing the resolution of existing regulatory issues pending in separate CPUC proceedings. Regulatory issues being negotiated as part of the Gas Accord include PG&E's capacity commitments with Transwestern, recovery of the costs for unbrokered capacity commitments under the ITCS mechanism and the reasonableness proceedings for the PG&E portion of the Pipeline Expansion. The Company believes the ultimate resolution of past and future Transwestern costs, the ITCS proceeding and the PG&E portion of the Pipeline Expansion proceedings, either through settlement negotiations or ongoing proceedings, will not have a material adverse impact on its financial position or results of operations.

Note 4: Diablo Canyon

Rate Case Settlement: The Diablo Settlement bases revenues primarily on the amount of electricity generated by the plant, rather than on traditional cost-based ratemaking. The Diablo Settlement provides that Diablo Canyon costs and operations should no longer be subject to CPUC reasonableness reviews and that only certain Diablo Canyon costs be recovered through base rates over the term of the Diablo Settlement, including a full return on such costs. The related revenues to recover these costs are included in Diablo Canyon operating revenues reported below. Other than for these and decommissioning costs, Diablo Canyon no longer meets the criteria for application of SFAS No. 71, which was discontinued for Diablo Canyon effective July 1988.

Pricing: In May 1995, the CPUC approved a modification to the pricing provisions of the Diablo Settlement. Under the modification, the prices for power produced by Diablo Canyon for 1996 through 1999 are 10.5 cents, 10.0 cents, 9.5 cents and 9.0 cents per kWh, respectively, effective January 1. PG&E has the right to reduce the price below the amount specified. All other terms and conditions of the Diablo Settlement remain unchanged.

The modification provides that the difference between PG&E's revenue requirement under the original Diablo Settlement prices and the modified prices be applied to PG&E's energy cost balancing account until the undercollection in that account as of December 31, 1995, is fully amortized.

Under the modified pricing, at full operating power each Diablo Canyon unit would contribute approximately $2.7 million in revenues per day in 1996.

The prices per kWh of electricity generated by Diablo Canyon for 1995, 1994 and 1993 were 11.00 cents, 11.89 cents and 11.16 cents per kWh, respectively.

Financial Information: Selected financial information for Diablo Canyon is shown below:

Year ended December 31, (In millions)	1995	1994	1993
Operating revenues	$1,845	$1,870	$1,933
Operating income before income taxes	1,029	956	1,123
Net income	507	461	496

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 corporate debt.

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, 1995, 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, 1995, 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, 1995. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding or 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, 1995 and 1994, was approximately $139 million and $117 million, respectively, based primarily on matrix pricing models.

During 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.

During 1994, PG&E issued $63 million of series 6.30% redeemable preferred stock and redeemed its series 8.16% redeemable preferred stock with a par value of $75 million.

Dividends on 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: In November 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 only assets of the Trust are the deferrable interest 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. 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. Net proceeds from the QUIPS offering and the issuance of the common securities were used by the Trust to purchase the subordinated debentures. Proceeds to PG&E from the sale of the subordinated debentures are being used to refinance higher-cost preferred stock.

Note 6: Long-term Debt

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

Mortgage Bonds: PG&E had $5.7 billion and $5.9 billion of mortgage bonds outstanding at December 31, 1995 and 1994, respectively. Additional bonds may be issued, subject to CPUC approval, up to a maximum total amount outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and property available as security. All real properties and substantially all personal properties of PG&E are subject to the lien of the indenture.

PG&E is required by the indenture to make semi-annual sinking fund payments on February 1 and August 1 of each year for the retirement of the bonds. These payments equal .5 percent of the aggregate bonded indebtedness outstanding on the preceding November 30 and May 31, respectively. Mortgage bonds, with certain exceptions, may be used to satisfy the sinking fund requirement.

In conjunction with PG&E's focus on reducing the levels of higher-cost debt, PG&E redeemed or repurchased $114 million and $80 million of higher-cost mortgage bonds in 1995 and 1994, respectively. Interest rates on the bonds redeemed or repurchased ranged from 8.875 percent to 12.75 percent.

Included in the total of outstanding mortgage bonds are First and Refunding Mortgage Bonds issued by PG&E to finance air and water pollution control and sewage and solid waste disposal facilities. These mortgage bonds are held in trust for the California Pollution Control Financing Authority (CPCFA), which arranged these financings, and are in addition to the Pollution Control Loan Agreements discussed below. At December 31, 1995 and 1994, PG&E had outstanding $768 million of mortgage bonds held in trust for the CPCFA with interest rates ranging from 5.85 percent to 8.875 percent and maturity dates from 2007 to 2023.

Pollution Control Loan Agreements: In addition to the pollution control loans secured by PG&E's mortgage bonds (described above), PG&E had loans totaling $925 million at December 31, 1995 and 1994, from the CPCFA, issued for similar purposes. Interest rates on the loans vary depending upon whether the loans are in a daily, weekly, commercial paper or fixed rate mode. Conversions from one mode to another take place at PG&E's option. Average annual interest rates on these loans for 1995 ranged from 3.77 percent to 3.90 percent. These loans are subject to redemption on demand by the holder under certain circumstances and are secured by irrevocable letters of credit which mature as early as 1997.

Long-term Debt of Subsidiaries: In 1995, PGT, a wholly owned subsidiary of PG&E, completed the sale of $470 million of debt securities through a $700 million shelf registration. Additionally, PGT issued commercial paper, $109 million of which was outstanding at December 31, 1995. This commercial paper is classified as long-term based upon the availability of committed credit facilities expiring in 2000 and management's intent to maintain such amounts in excess of one year. Substantially all of the proceeds from the debt offering and sale of commercial paper were used to refinance $600 million of outstanding PGT debt.

Repayment Schedule: At December 31, 1995, the Company's combined aggregate amount of maturing long-term debt and sinking fund requirements, for the years 1996 through 2000, are $304 million, $322 million, $668 million, $271 million and $447 million, respectively.

Fair Value: The estimated fair value of the Company's total long-term debt of $8.4 billion and $9.2 billion at December 31, 1995 and 1994, respectively, was approximately $8.7 billion and $8.6 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., matrix pricing models or the present value of future cash flows).

Note 7: Short-term Borrowings

Substantially all short-term borrowings consist of commercial paper. The usual maturity for commercial paper is one to ninety days. Commercial paper outstanding at December 31, 1995 and 1994, was $796 million with a weighted average interest rate of 5.92 percent and $525 million with a weighted average interest rate of 6.18 percent, respectively. The carrying amount of short-term borrowings approximates fair value.

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 also can be used for general corporate purposes. There were no borrowings under this facility in 1995 or 1994. This credit facility expires in November 2000; however, it may be extended annually for additional one-year periods upon mutual agreement among PG&E and the banks.

Note 8: Investments in Debt and Equity Securities

Effective January 1, 1994, the Company adopted SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," which established new financial accounting and reporting standards for investments in debt and equity securities. All of PG&E's investments in debt and equity securities are included in Nuclear Decommissioning Funds and are classified as available-for-sale. These securities are held in external trust funds to be used for the decommissioning of PG&E's nuclear facilities and are reported at fair value. Unrealized gains and losses are recorded to Accumulated Depreciation and Decommissioning, net of tax. Funds may not be released from the external trust funds until authorized by the CPUC.

The proceeds received during 1995 and 1994 from the sale of securities held as available-for-sale were approximately $1.5 billion and $1 billion, respectively. During 1995 and 1994, the gross realized gains on sales of securities held as available-for-sale were $9 million and $10 million, respectively, and the gross realized losses on sales of securities held as available-for-sale were $22 million and $12 million, respectively. The cost of equity securities sold is determined by specific identification. The cost of debt securities sold is based on a first-in-first-out method.

The following tables provide a summary of amortized cost and fair value by major security type:

December 31, 1995	Amortized Cost	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Fair Value
(in thousands)				
Debt of U.S. Treasury and other federal entities	$332,847	$ 21,157	$ –	$354,004
State and local obligations	45,086	2,716	(97)	47,705
Equity securities	277,460	93,767	(2,759)	368,468
Other securities and adjustments	(377)	33	(4)	(348)
Total nuclear decommissioning funds	$655,016	$117,673	$(2,860)	$769,829

December 31, 1994 (in thousands)	Amortized Cost	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Fair Value
Debt of U.S. Treasury and other federal entities	$290,511	$ 20	$ (7,972)	$ 282,559
State and local obligations	94,899	1,268	(2,485)	93,682
Equity securities	184,954	18,556	(9,261)	194,249
Other securities and adjustments	46,398	24	(275)	46,147
Total nuclear decommissioning funds	$616,762	$19,868	$(19,993)	$616,637

At December 31, 1995 and 1994, investments in debt securities maturing within ten years totaled $275 million and $293 million, respectively, and investments in debt securities with maturities in excess of ten years totaled $146 million and $114 million, respectively.

Note 9: Employee Benefit Plans

Retirement Plan: PG&E provides a noncontributory defined benefit pension plan covering substantially all employees. Retirement benefits are based on years of service and the employee's base salary. PG&E'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. Other than for voluntary retirement incentive (VRI) benefits, PG&E last funded the retirement plan in 1992, consistent with amounts recovered in rates.

At December 31, 1995, plan assets exceeded the projected benefit obligation by $739 million. The plan's funded status was:

December 31, (in thousands)	1995	1994
Actuarial present value of benefit obligations		
Vested benefits	$(3,464,782)	$(3,079,045)
Nonvested benefits	(182,503)	(131,489)
Accumulated benefit obligation	(3,647,285)	(3,210,534)
Effect of projected future compensation increases	(548,743)	(441,951)
Projected benefit obligation	(4,196,028)	(3,652,485)
Plan assets at market value	4,935,267	4,169,516
Plan assets in excess of projected benefit obligation	739,239	517,031
Unrecognized prior service cost	90,496	93,425
Unrecognized net gain	(1,074,347)	(908,485)
Unrecognized net transition obligation	97,348	108,800
Accrued pension liability	$ (147,264)	$ (189,229)

Plan assets are primarily 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 amortized over approximately 18 years, beginning in 1987.

The vested benefit obligation is the actuarial present value of vested benefits to which employees are currently entitled based on their expected termination dates.

The cost of this plan is recorded to expense and, on a funding basis, to plant in service. Net pension cost or income, using the projected unit credit actuarial cost method, was:

Year ended December 31, (In thousands)	1995	1994	1993
Service cost for benefits earned	$ 82,814	$109,132	$129,166
Interest cost	290,563	272,932	268,698
Actual (return) loss on plan assets	(968,126)	20,358	(511,526)
Net amortization and deferral	586,350	(412,547)	177,597
Net pension (income) cost	$ (8,399)	$ (10,125)	$ 63,935

Actuarial assumptions used in accounting for the pension plan were:

December 31,	1995	1994	1993
Discount rate	7.25%	8%	7%
Rate of future compensation increases	5%	5%	5%
Expected long-term rate of return on plan assets	9%	9%	9%

Net pension cost or income is determined using assumptions at the beginning of the year. Funded status is determined using assumptions at the end of the year.

The decrease in net pension cost in 1994 compared to 1993 was primarily due to changes in the assumed rates of future compensation increases and turnover to better reflect actual and expected rates.

Net pension cost or income 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 pension cost or income. In 1995 and 1993, 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 accounting for rate-regulated enterprises, regulatory adjustments have been recorded in the income statement and balance sheet for the difference between utility pension cost determined for accounting purposes and that for ratemaking, which is based on a funding approach.

Savings Fund Plan: PG&E sponsors a defined contribution pension plan. Employees with at least one year of service may contribute up to 15 percent of their covered compensation on a pretax or after-tax basis. These contributions, up to a maximum of six percent of covered compensation, are eligible for matching PG&E contributions at specified rates. The cost of PG&E contributions was charged to expense and to plant in service and totaled $33 million, $35 million and $36 million for 1995, 1994 and 1993, respectively.

Postretirement Benefits Other Than Pensions: PG&E provides a contributory defined benefit medical plan for retired employees and their eligible dependents and a noncontributory defined benefit life insurance plan 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 PG&E's retirees. The cost of these plans is charged to expense and to plant in service.

The CPUC has authorized recovery of these benefits for 1993 and beyond, within certain guidelines, at a level equal to the annual accounting cost, based on amortization of the transition obligation over 20 years, limited by the amount which can be contributed annually on a tax-deductible basis to appropriate trusts. PG&E's policy for postretirement medical and life insurance benefits is to fund each year an amount consistent with the basis for rate recovery.

In 1993, PG&E implemented a plan change that will limit the amount it will contribute toward postretirement medical benefits beginning in 2001. This change reduced the accumulated postretirement benefit obligation at July 1, 1993, by approximately $450 million.

At December 31, 1995, the accumulated postretirement benefit obligation exceeded plan assets by $422 million. The medical and life insurance plans' funded status was:

December 31, (In thousands)	1995	1994
Accumulated postretirement benefit obligation		
Retirees	$(528,367)	$(497,889)
Other fully eligible participants	(123,615)	(104,865)
Other active plan participants	(309,405)	(219,639)
Total accumulated postretirement benefit obligation	(961,387)	(822,393)
Plan assets at market value	538,905	394,939
Accumulated postretirement benefit obligation in excess of plan assets	(422,482)	(427,454)
Unrecognized prior service cost	23,761	25,377
Unrecognized net gain	(104,167)	(115,249)
Unrecognized transition obligation	449,647	462,082
Accrued postretirement benefit liability	$ (53,241)	$ (55,244)

Plan assets are primarily 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 amortized over 20 years, beginning in 1993.

Net postretirement medical and life insurance cost, using the projected unit credit actuarial cost method, was:

Year ended December 31, (In thousands)	1995	1994	1993
Service cost for benefits earned	$ 17,004	$23,617	$ 38,496
Interest cost	64,776	64,872	73,502
Actual return on plan assets	(108,932)	(1,232)	(23,999)
Amortization of unrecognized prior service cost	1,616	1,711	—
Amortization of transition obligation	26,533	28,913	39,620
Net amortization and deferral	70,070	(29,804)	(3,390)
Net postretirement benefit cost	$ 71,067	$88,077	$124,229

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 1995, 1994 and 1993 were the same as those used for the pension plan. The assumed health care cost trend rate for 1996 is approximately 10.5 percent, grading down to an ultimate rate in 2005 of approximately 6 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, 1995, by approximately $117 million and the 1995 aggregate service and interest costs by approximately $12 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. The decrease in cost in 1994 compared to 1993 was primarily due to the plan change implemented July 1, 1993, that will limit PG&E's contributions toward postretirement medical benefits.

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 1995, actual return on plan assets exceeded expected return. In 1994 and 1993, actual return on plan assets was less than expected.

Workforce Reductions: The effects of workforce reductions announced by PG&E in 1994 and 1993 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 implemented a Long-term Incentive Program (Program) in 1992. The Program allows eligible participants to be granted stock options with or without associated stock appreciation rights, dividend equivalents and/or performance-based units. The Program incorporates those shares previously authorized under PG&E's 1986 Stock Option Plan. As of December 31, 1995, a total of 14.5 million shares of common stock have been authorized for award under the Program and the 1986 Stock Option Plan. During 1995, an additional 10 million common shares were authorized for award under the Program, subject to shareholder approval. At December 31, 1995, stock options on 2,761,290 shares, granted at option prices ranging from $16.75 to $34.25, were outstanding. During 1995, 570,500 options were granted at an option price of $24.38, 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 1995, 1994 and 1993, stock options on 235,568, 52,143 and 174,387 shares, respectively, were exercised at option prices ranging from $16.75 to $33.13, $24.75 to $32.13 and $16.75 to $33.13, respectively. At December 31, 1995, stock options on 1,337,196 shares were exercisable.

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 and $52 million for other postretirement benefits both extended in connection with the VRI as well as $61 million of estimated severance costs. The majority of the severances were in generation and transmission functions. PG&E will 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 order to accelerate maintenance on its system in light of the severity of the damage caused by storms in the winter 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 $18.2 million in 1995.

The total cost of the 1993 workforce reductions was $264 million. Included in this amount was $151 million for additional pension benefits and $22 million for other postretirement benefits extended in connection with the VRI. As a result of a freeze on electric rates, PG&E expensed $190 million of costs relating to electric operations. The amount relating to gas operations was deferred and amortized over the period 1993–1995.

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 deferred and amortized to income over the life of the related property.

The significant components of income tax expense were:

Year ended December 31, (In thousands)	1995	1994	1993
Current	$1,011,358	$821,455	$582,692
Deferred	(97,864)	34,657	339,608
Tax credits—net	(18,205)	(19,345)	(20,410)
Total income tax expense	$ 895,289	$836,767	$901,890

The significant components of net deferred income tax liabilities were:

December 31, (In thousands)	1995	1994
Deferred income tax assets:		
Deferred income taxes—current	$ 195,510	$ 173,357
Deferred income taxes—noncurrent	1,008,471	959,459
Total deferred income tax assets	1,203,981	1,132,816
Deferred income tax liabilities:		
Deferred income taxes—current		
Regulatory balancing accounts	385,604	559,750
Other	37,688	45,633
Total deferred income taxes—current	423,292	605,383
Deferred income taxes—noncurrent		
Plant in service	3,552,974	3,627,294
Income tax-related deferred charges[1]	443,152	474,242
Other	946,110	760,568
Total deferred income taxes—noncurrent	4,942,236	4,862,104
Total deferred income tax liabilities	5,365,528	5,467,487
Total net deferred income taxes	$4,161,547	$4,334,671
Classification of net deferred income taxes:		
Included in current liabilities	$ 227,782	$ 432,026
Included in deferred credits	3,933,765	3,902,645
Total net deferred income taxes	$4,161,547	$4,334,671

(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,	1995	1994	1993
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)	4.8	8.3	6.5
Effect of regulatory treatment of depreciation differences	3.2	3.7	4.5
Tax credits—net	(.8)	(1.1)	(1.0)
Other—net	(2.1)	(.5)	.8
Effective tax rate	40.1%	45.4%	45.8%

Note 12: Commitments

Capital Projects: Capital expenditures for 1996 are estimated to be approximately $1,489 million, consisting of $1,291 million for utility expenditures, $36 million for Diablo Canyon expenditures and $162 million for expenditures from diversified operations.

At December 31, 1995, Enterprises had firm commitments totaling $143 million 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 $114 million in 1996 and $29 million in 1997.

Qualifying Facilities: Under the Public Utility Regulatory Policies Act of 1978, PG&E is required to purchase electric energy and capacity provided by QFs. The CPUC established a series of power purchase agreements which set the applicable terms, conditions and price options. The total cost of prudently incurred energy and capacity payments to QFs is recoverable in rates. PG&E's contracts with QFs expire on various dates from 1996 to 2026. Under these contracts, PG&E is required to make payments only when energy is supplied or when capacity commitments are met. Payments to QFs are expected to vary in future years, with a decline in payments expected in the years 1998 through 2000 under the terms of the QF contracts.

In 1995 and 1994, PG&E negotiated early termination or suspension of certain QF contracts at a cost of $142 million and $155 million, respectively, to be paid through 1999. These amounts are expected to be recovered in rates. At December 31, 1995, $159 million remained to be paid to QFs for early termination or suspension.

QF deliveries in the aggregate account for approximately 20 percent of PG&E's 1995 electric energy requirements, and no single contract accounted for more than 5 percent of PG&E's energy needs. QF deliveries in 1995 represented approximately 83 percent of the QFs' plant output, in the aggregate. The amount of energy received from QFs and the total energy and capacity payments made under these agreements were:

Year ended December 31, (In millions)	1995	1994	1993
Kilowatt-hours received	20,496	21,699	21,242
Energy payments	$1,140	$1,196	$1,099
Capacity payments	$ 484	$ 518	$ 503

Other Power Purchases: PG&E has contracts with various irrigation districts and water agencies to purchase hydroelectric power. The contracts expire on various dates from 2004 to 2031. 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. Additional variable payments for operation and maintenance costs incurred by the providers are also required to be made under the contracts. The total cost of these payments is recoverable in rates. At December 31, 1995, the undiscounted future minimum payments under these contracts are $34 million for each of the years 1996 through 2000 and a total of $417 million for periods thereafter. Total payments under these contracts were $50 million, $49 million and $45 million in 1995, 1994 and 1993, respectively.

Note 13: Contingencies

Nuclear Insurance: PG&E is a member of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL). Under these policies, if the nuclear generating facility of a member utility suffers a property damage loss or a business interruption loss due to a prolonged accidental outage, PG&E may be subject to maximum assessments of $26 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.

Federal law requires all utilities with nuclear generating facilities to share in payment for claims resulting from a nuclear incident and limits industry liability for third-party claims to $8.9 billion per incident. Coverage of the first $200 million is provided by a pool of commercial insurers. 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 records its environmental liabilities when site assessments and/or remedial actions are 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 probable amount, the Company records the lower end of this reasonably likely range of costs (classified as other noncurrent liabilities). The Company may be required to pay for remedial action at sites where the Company has been or may be a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA; federal Superfund law) or the California Hazardous Substance Account Act (California Superfund law). 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 wastes, even if the Company did not deposit those wastes on the site.

The overall costs of the hazardous materials and hazardous waste compliance and remediation activities ultimately undertaken by the Company are difficult to estimate, and 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, 1995, of $122 million for hazardous waste remediation costs at those sites where such costs are probable and quantifiable. The costs may be as much as $287 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, among 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 waste compliance and remediation costs through ratemaking procedures approved by the CPUC, through insurance and through other recoveries from third-parties. While the Company has numerous insurance policies that it believes may provide coverage for some of these liabilities, it does not recognize insurance or third-party recoveries in its financial statements until they are realized. 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 book value of $631 million at December 31, 1995. As part of the 1996 GRC decision in December 1995, the CPUC directed PG&E to perform a cost-effectiveness study of Helms, to be submitted in July 1996. The study will consider changes in rate recovery for the plant which will include, among other things, the option of retirement with recovery of the investment without a return.

PG&E is currently unable to predict whether there will be a change in rate recovery resulting from the study. 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.

Legal Matters:

Stanislaus Litigation: A lawsuit was filed by the County of Stanislaus, California, and a residential customer of PG&E, purportedly as a class action on behalf of all natural gas customers of PG&E during the period of February 1988 through October 1993. The lawsuit alleged that the purchase of natural gas in Canada by Alberta and Southern Gas Co. Ltd., a subsidiary of PG&E, was accomplished in violation of various antitrust laws and sought damages of as much as $950 million, before trebling.

In December 1995, a federal district court dismissed the lawsuit. The plaintiffs have the right to appeal the dismissal to the Court of Appeals. The Company believes that the ultimate outcome of this matter will not have a material adverse impact on its financial position.

Hinkley Litigation: In 1993, a complaint was filed in a state superior court on behalf of individuals seeking recovery of an unspecified amount of damages for personal injuries and property damage allegedly suffered as a result of exposure to chromium near PG&E's Hinkley Compressor Station, as well as punitive damages. The original complaint has been amended, and additional complaints have been filed to include additional plaintiffs.

The plaintiffs contend that PG&E discharged chromium-contaminated wastewater into unlined ponds to avoid costly alternatives, which led to chromium percolating into the groundwater of surrounding property.

PG&E has reached an agreement with plaintiffs pursuant to which those plaintiffs' actions will be submitted to binding arbitration for resolution of issues concerning the cause and extent of any damages suffered by plaintiffs as a result of the alleged chromium contamination. Under the terms of the agreement, PG&E will pay an aggregate amount of no more than $400 million in settlement of such plaintiffs' claims. In turn, those plaintiffs, and their attorneys, agree to indemnify PG&E against any additional losses PG&E may incur with respect to related claims pursued by the identified plaintiffs who do not agree to this settlement or by other third parties who may be sued by the plaintiffs in connection with the alleged chromium contamination.

As of December 31, 1995, PG&E has paid $50 million to escrow and recorded an additional $150 million reserve against any future potential liability in this case. The Company believes the ultimate outcome of this matter will not have a material adverse impact on its financial position or results of operations.

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 fees at different rates from other cities.

In September 1995, the Court certified the class of 107 cities in this action and approved the City of Santa Cruz as the class representative. In January 1996, the Court granted PG&E's motion for summary judgment against certain plaintiffs and various motions effectively eliminating a major portion of the class action. The Court's rulings do not resolve the case completely.

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 $17 million and damages for alleged underpayments for the years 1987 to 1995 could be as much as $131 million (exclusive of interest, estimated to be $31 million as of December 31, 1995). If the Court's January 1996 rulings become final, PG&E's annual systemwide city electric franchise fees for the remaining class member cities could increase by approximately $5.3 million and damages for alleged underpayments for the years 1987 to 1995 could be as much as $39.1 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.

Quarterly Consolidated Financial Data (Unaudited)

Pacific Gas and Electric Company

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.

PG&E recorded an increase of $50 million in litigation reserves in the first and third quarters of 1995.

In the first quarter of 1994, PG&E took a charge against earnings of approximately $90 million as a result of the CPUC disallowances in the gas reasonableness proceedings for 1988 through 1990 and PG&E's assessment of open reasonableness issues. In the second quarter of 1994, PG&E increased its litigation reserves by $50 million. In the fourth quarter of 1994, PG&E took a charge against earnings of $249 million related to 1994 workforce reductions.

PG&E's common stock is traded on the New York, Pacific, London, Amsterdam, Basel and Zurich stock exchanges. There were approximately 220,000 common shareholders of record at December 31, 1995. Dividends are paid on a quarterly basis, and there are no significant restrictions on the present ability of PG&E to pay dividends.

Quarter ended (In thousands, except per share amounts)	December 31	September 30	June 30	March 31
1995				
Operating revenues(1)	$2,227,224	$2,637,653	$2,448,641	$2,308,247
Operating income(1)	451,674	781,912	820,370	709,029
Net income	227,085	377,593	405,520	328,687
Earnings per common share(2)	.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
1994				
Operating revenues(1)	$2,619,484	$2,840,962	$2,444,457	$2,445,327
Operating income(1)	306,270	889,658	611,901	615,957
Net income	103,500	425,633	241,365	236,952
Earnings per common share(2)	.21	.96	.53	.52
Dividends declared per common share	.49	.49	.49	.49
Common stock price per share				
High	25.25	25.13	29.75	35.00
Low	21.38	22.00	22.50	28.50

(1) Operating revenues and operating income have been reclassified to conform with the 1995 presentation of the Statement of Consolidated Income.
(2) Includes Diablo Canyon scheduled refueling outages which impacted earnings per common share for the fourth quarter in 1995 and all quarters in 1994. In addition, Diablo Canyon experienced unscheduled outages in the third and fourth quarters of 1995 and in the second quarter of 1994.

Report of Independent Public Accountants

Pacific Gas and Electric Company

To the Shareholders and the Board of Directors of Pacific Gas and Electric Company:

We have audited the accompanying consolidated balance sheet and the statement of consolidated capitalization of Pacific Gas and Electric Company (a California corporation) and subsidiaries as of December 31, 1995 and 1994, 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, 1995. 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 schedule 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 Pacific Gas and Electric Company and subsidiaries as of December 31, 1995 and 1994, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP
San Francisco, California
February 12, 1996

Responsibility for Consolidated Financial Statements

Pacific Gas and Electric Company

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 have 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, effective internal controls and unbiased, 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.

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Pacific Gas and Electric Company

Board of Directors

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Chairman of the Board, Retired
Pacific Gas and Electric Company

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Chief Executive Officer,
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Vice Chairman,
AirTouch Communications
and President and Chief
Executive Officer,
AirTouch Cellular

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(retail grocery)

Robert D. Glynn, Jr.
President and
Chief Operating Officer,
Pacific Gas and Electric Company

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

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Chairman of the Board and
Chief Executive Officer, Retired
Potlatch Corporation
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University of California, Berkeley

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Chief Executive Officer
Joint Venture:
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(nonprofit collaborative
formed to address critical
issues facing Silicon Valley)

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Chief Executive Officer, Retired
Wells Fargo & Company and
Wells Fargo Bank, N.A.

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Chief Executive Officer,
The Nature Conservancy
(international environmental
organization)

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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,
Pacific Gas and Electric Company

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

Permanent Committees of the Board of Directors

Executive Committee
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 Committee
Reviews 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

Finance Committee
Recommends long-range financial policies and objectives, and actions required to achieve those objectives.

Richard B. Madden (Chair)
Richard A. Clarke
Carl E. Reichardt
Stanley T. Skinner
Barry Lawson Williams

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

Carl E. Reichardt (Chair)
David M. Lawrence, MD
Samuel T. Reeves
John C. Sawhill
Alan Seelenfreund

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

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

Officers

Pacific Gas and Electric Company

PG&E Officers

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Chairman of the Board and
Chief Executive Officer

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

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Executive Vice President

Robert J. Haywood
Senior Vice President and
General Manager,
Customer Energy Services

Thomas W. High
Senior Vice President
Corporate Services

Jack F. Jenkins-Stark
Senior Vice President and
General Manager,
Gas Supply Business Unit

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

Gordon R. Smith
Senior Vice President and
Chief Financial Officer

Bruce R. Worthington
Senior Vice President and
General Counsel

Shan Bhattacharya
Vice President
Technical and
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Lee Callaway
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Corporate Communications

John C. Danielsen
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Computer and
Telecommunications Services

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Warren H. Fujimoto
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Diablo Canyon Operations and
Plant Manager

Anthony Harris
Vice President
Sales

Robert L. Harris
Vice President
Community Relations

Kent M. Harvey
Vice President and Treasurer

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Customer Services

Steven L. Kline
Vice President
Regulation

Thomas C. Long
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E. James Macias
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General Manager
Electric Transmission
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Nuclear Technical Services

Leslie H. Everett
Corporate Secretary

Eric Montizambert
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Gabriel B. Togneri
Assistant Treasurer

Chief Executive Officers of Principal PG&E Subsidiaries

Tony F. DiStefano
Chairman, Chief Executive
Officer, and President
PG&E Enterprises

Stephen P. Reynolds
President and
Chief Executive Officer
Pacific Gas Transmission
Company

Chief Executive Officers of Principal PG&E Enterprises Subsidiaries and Related Ventures

Earl H. Franklin
President and
Chief Executive Officer
U.S. Operating Services
Company

Robert Frommer
President
PG&E Properties, Inc.

Junona A. Jonas
President and
Chief Operating Officer
Vantus Energy Corp.

Joseph P. Kearney
President and
Chief Executive Officer
U.S. Generating Company

Carlos A. Riva
President and
Chief Executive Officer
International Generating
Company

Shareholder Services Office
77 Beale Street, Room 2600
San Francisco, CA 94105
1-800-367-7731

If you have questions about your account or need copies of the Company's publications, please write or call the Shareholder Services Office at:

Manager of Shareholder Services
David M. Kelly
77 Beale Street, B26B
P.O. Box 770000
San Francisco, CA 94177
1-800-367-7731

If you have general questions about PG&E, please write or call the Office of the Corporate Secretary at:

Corporate Secretary
Leslie H. Everett
77 Beale Street, B32
P.O. Box 770000
San Francisco, CA 94177
(415) 973-2880

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

Manager of Investor Relations
Angela M. Comstock
77 Beale Street, B8C
P.O. Box 770000
San Francisco, CA 94177
(415) 973-3007

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 PG&E in the broker's name, or "street name." The Company does 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, publications, and proxy materials through your broker. If you are receiving unwanted duplicate mailings, you should contact your broker to eliminate the duplications.

Dividend Reinvestment Plan
If you hold stock in your own name, rather than through a broker, you may automatically reinvest dividend payments from common and preferred stock in new shares of PG&E common stock through the Dividend Reinvestment 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 directly in PG&E's Dividend Reinvestment Plan.

Direct Deposit of Dividends
If you hold stock in your own name, rather than through a broker, you may have your common and preferred dividends transmitted to your bank electronically. You may obtain a brochure describing the Direct Deposit features and enrollment 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 issued.

Lost or Stolen 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 in writing or by telephone.

Annual Meeting of Shareholders

Date: April 17, 1996
Time: 10:00 a.m.
Location: Masonic Auditorium
1111 California Street
San Francisco, California

A notice of the meeting, proxy statement and prospectus, and proxy form are being mailed with this annual report on or about February 29, 1996, to all shareholders of record as of February 20, 1996.

1996 Dividend Payment Dates

Common Stock	Preferred Stock
January 15	February 15
April 15	May 15
July 15	August 15
October 15	November 15

Stock Exchange Listings

PG&E's common stock is traded on the New York, Pacific, London, Basel, Zürich and Amsterdam stock exchanges. The official New York Stock Exchange symbol is "PCG" but the PG&E common stock is usually listed in the newspaper under "PacGE."

The Company has 13 issues of preferred stock and one issue of preferred security, all of which are listed on the American Stock Exchange and the Pacific Stock Exchange.

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 pfL
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

*Newspaper symbol may vary

10-K Report

If you would like a copy of the Company's 1995 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: http://www.pge.com

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PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
http://www.pge.com