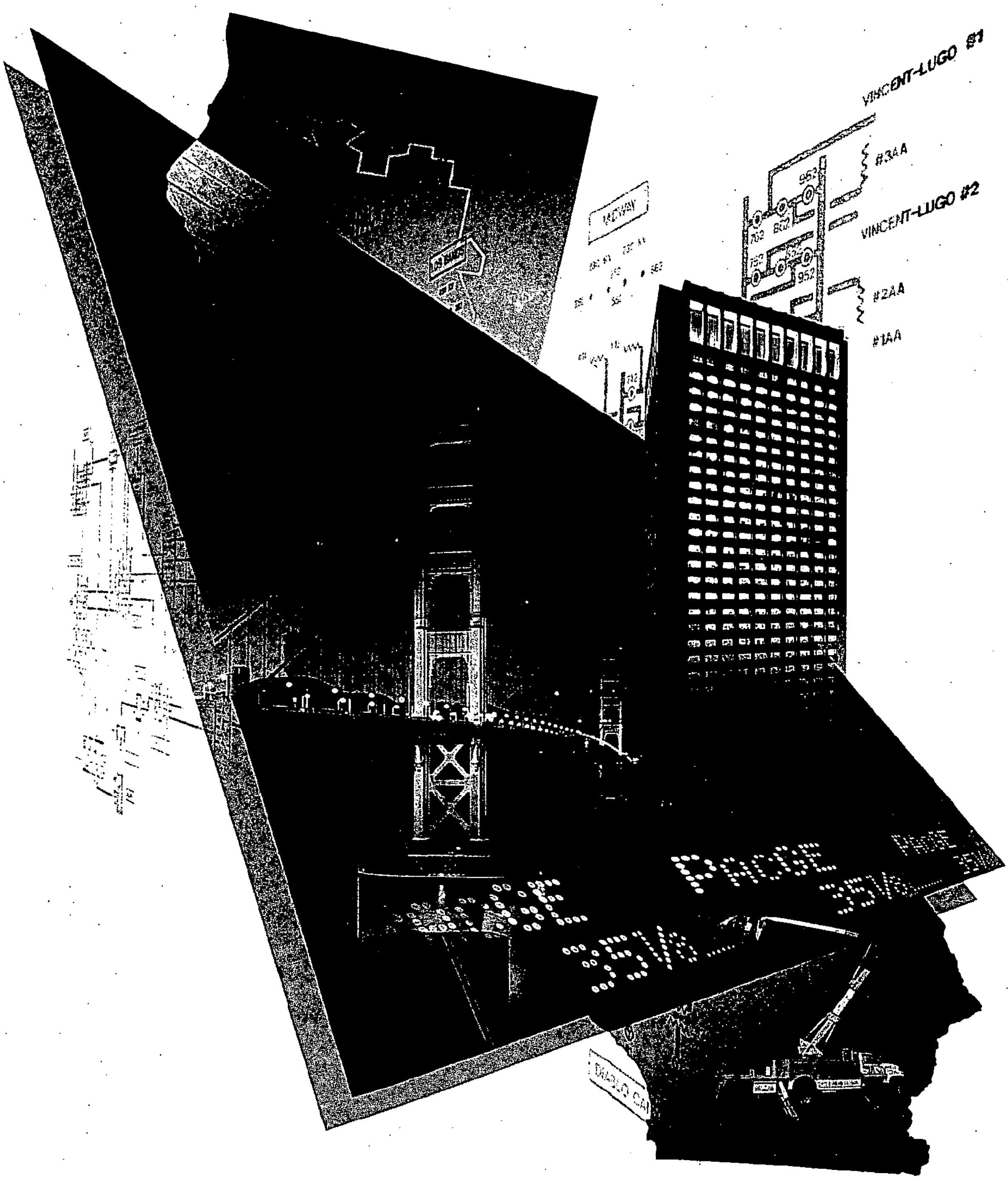
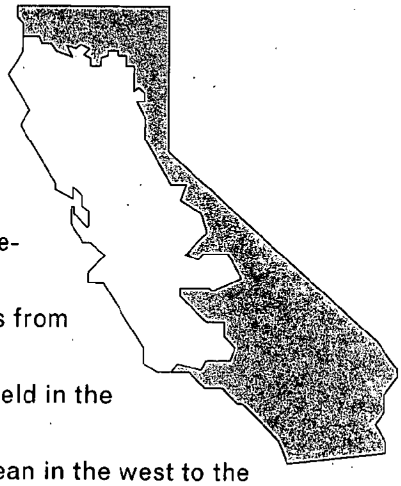
Pacific Gas and Electric Company 1993 Annual Report



On course in changing times

PG&E is the nation's largest investor-owned gas and electric utility, serving 12.8 million people in Northern and Central California. Our electricity comes from widely diversified resources – fossil-fuel plants, hydroelectric plants, a major pumped storage plant, a geothermal complex, the Diablo Canyon Nuclear Power Plant and from such renewable technologies as wind power, solar power and biomass. Our natural gas comes from Canada, the U.S. Southwest and California.

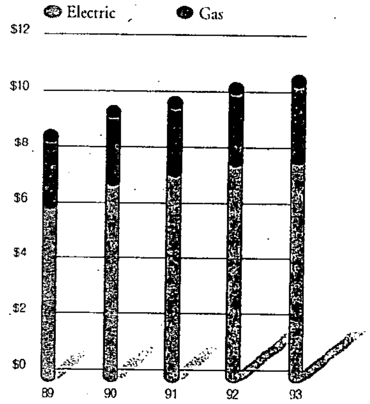


The company's 94,000 square-mile service territory stretches from Eureka in the north to Bakersfield in the south and from the Pacific Ocean in the west to the Sierra Nevada in the east.

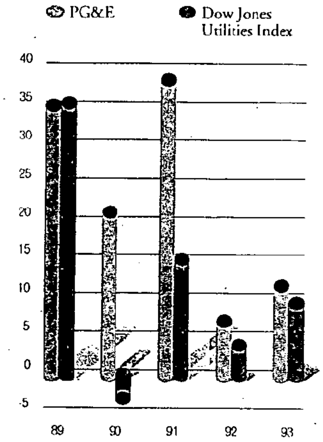
Contents

(dollars in thousands, except per share amounts)	1993	1992	% Change
For the Year			
Operating revenues	**$10,582,408**	$10,296,088	2.8
Operating income	**$ 1,762,930**	$ 1,833,441	(3.8)
Net income	**$ 1,065,495**	$ 1,170,581	(9.0)
Earnings available for common stock	**$ 1,001,683**	$ 1,091,694	(8.2)
Earnings per common share	**$2.33**	$2.58	(9.7)
Dividends declared per common share	**$1.88**	$1.76	6.8
Construction expenditures (including AFUDC)	**$ 1,883,181**	$ 2,390,903	(21.2)
Total electric sales to customers (kWh – in thousands)	**75,653,342**	75,285,241	.5
Total gas sales to customers (Mcf – in thousands)	**430,718**	429,109	.4
At Year End			
Total assets	**$27,162,526**	$24,188,159	12.3
Total electric customers	**4,363,414**	4,301,124	1.4
Total gas customers	**3,558,800**	3,533,700	.7
Number of common shareholders	**245,000**	254,000	(3.5)
Number of common shares outstanding	**427,219,205**	426,845,569	.1
Number of employees (excluding subsidiaries)	**23,000**	26,600	(13.5)

Consolidated Operating Revenue
(in billions)



Total Return on Common Stock Investment
(in percent)



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On Course In Changing Times. The competitive forces that were only a hint on the horizon a decade ago dominate today's energy utility industry. With competition has come change – frequent, rapid and profound change – in the way we do business. The strategy and goals we began formulating in the mid-1980s have served as a corporate compass, keeping us on course in the changing currents of the 1990s.

Now, as new challenges and opportunities emerge, PG&E is responding quickly and aggressively, taking action to remain competitive and meet our customers' changing needs and expectations. Our basic objective, however, remains the same: to produce solid financial results for our shareholders.

Our results in 1993 reflect both the company's fundamental operating strength and actions we have taken to sustain our success. Earnings in 1993 were $2.33 per share, a decline of 25 cents from the $2.58 per share earned in 1992. This decline was due to a number of factors. They include charges for the costs of our corporate reorganization, a key step that will enable us to remain competitive, and the restructuring of our gas supply and transportation business. In addition, 1993 earnings reflect the impact of a pending decision by the California Public Utilities Commission concerning the reasonableness of PG&E's gas purchases and an income tax adjustment related to Diablo Canyon. Exclusive of these write-offs and other one-time charges, our earnings from ongoing operations were $2.95.

Demonstrating its confidence in the company's prospects, the Board of Directors on January 19, 1994, raised the common stock quarterly dividend to 49 cents per share. This marked the fifth consecutive dividend increase posted by PG&E, and brought the new annualized rate to $1.96 per share, compared to the previous rate of $1.88.

Since 1988, we have provided shareholders an average total return of more than 22 percent annually, compared to about 11 percent for the Dow Jones Utilities Index.

These results reflect a company that has strong strategic foundations yet is also capable of change. Our mission and goals – to provide superior returns to shareholders and safe, dependable service to customers; to operate Diablo Canyon safely and efficiently; to improve the quality of the environment; to contribute to the economic and social well-being of the communities we serve; in short, to be a national leader in our industry – have not changed since they were developed almost a decade ago.

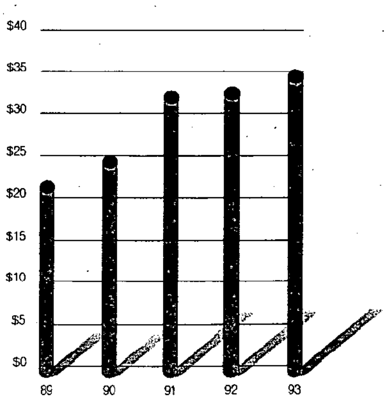
But our markets and the way we serve them have. And we are changing with them to effectively manage the company's transition to a new, more competitive era. We know this transition will not be easy.

Strong Competitors. The days when utilities were the sole supplier, transporter and distributor of gas and electricity are coming to an end. Strong competitors in the gas supply and electric generation businesses have emerged, unimpeded by traditional utility regulation. In fact, federal and state regulators are allowing these competitors increased access to utility gas pipelines and electric transmission facilities that once were the proprietary systems of the utilities.

At the same time, the slow growth of the economy and lower interest rates are making it more difficult to build the earnings needed to sustain the same level of dividend increases as in the past. Economic growth is running about 1 percent or less annually in California, about 2 percent below the U.S. growth rate. California's lagging recovery is mirrored in slow growth in electric use, which reduces our opportunity to build earnings through investment in facilities to serve new load.

Lower interest rates are a two-edged sword. They are a benefit in that they enable us to reduce our costs

Common Stock Market Price at Year End



for capital by refinancing our securities. But the cost of capital also determines the level of return on utility equity (ROE) regulators will allow. Lower interest rates mean lower ROEs. For 1994, PG&E's authorized utility return on equity is 11 percent, compared to 11.9 percent last year.

Our company brings some special strengths to this new era. First, we have gained a great deal of knowledge about competition from the restructuring of the gas business. Virtually all of that restructuring is completed. We have successfully terminated some 500 supply contracts with about 190 Canadian gas producers. And we have moved into a market in which our major customers have greater opportunity to purchase their own gas supplies, relying on PG&E for transport service only.

The 844-mile-long expansion of the Pacific Gas Transmission (PGT) - PG&E pipeline from Canada was completed on schedule in 1993. It began to transport gas to new industrial and utility customers in the Pacific Northwest and California on November 1.

In an era that is likely to see more volatile earnings results, PG&E is prepared financially. Our dividend-to-earnings payout ratio is less than similarly positioned energy utilities. We also have a strong cash flow position. This gives us the flexibility needed to take advantage of investment opportunities as they emerge.

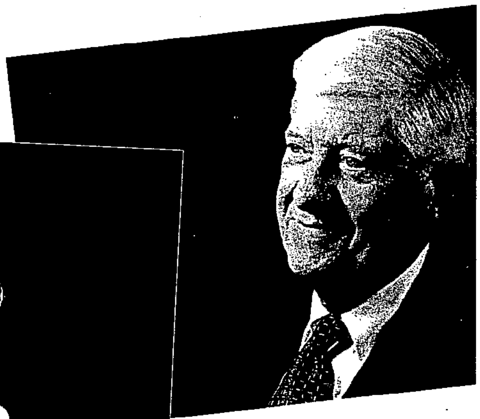
From this position of strength, we are addressing increased competition in our gas and electric business. We're taking aggressive steps to reduce costs, limit price rises for gas and particularly electricity, and increase productivity. We also have intensified our focus on providing customers excellent service. PG&E is becoming a leaner, more flexible, more competitive company.

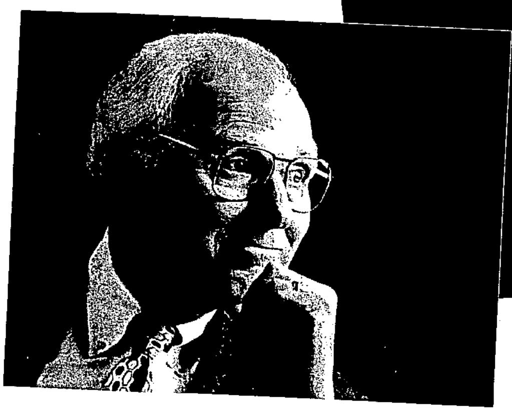
In the last year, we further reorganized, eliminating about 3,000 positions. This reorganization will not only cut costs significantly, it will also enable us to move more quickly, with fewer layers of management standing between a market challenge and our response. We are finding new ways to use the innovation and experience of employees to increase productivity. We are gaining more information than ever before about what our customers want and need from us. And we will translate that information into improved service.

Finally, the California Public Utilities Commission is reforming the regulatory process with increased reliance on incentive ratemaking. This change in determining rates would reward us for good operating performance much like any other competitive company. In turn, we expect incentive ratemaking to remove many of the current regulatory impediments to success in a fast-changing, competitive marketplace.

We don't underestimate the challenge our company faces in this transition to a more competitive era. We are moving ahead from a position of strength. Our strategy and goals will keep us on course. We are confident we will continue to succeed because we have a team of motivated and well-trained employees who have shown they can manage change effectively and find the new opportunities change brings.

In the pages that follow, we outline the major issues shaping this era and the actions PG&E is taking to continue the company's success – for our shareholders, our customers, our employees and the communities we serve.





[redacted]

Chairman of the Board and
Chief Executive Officer

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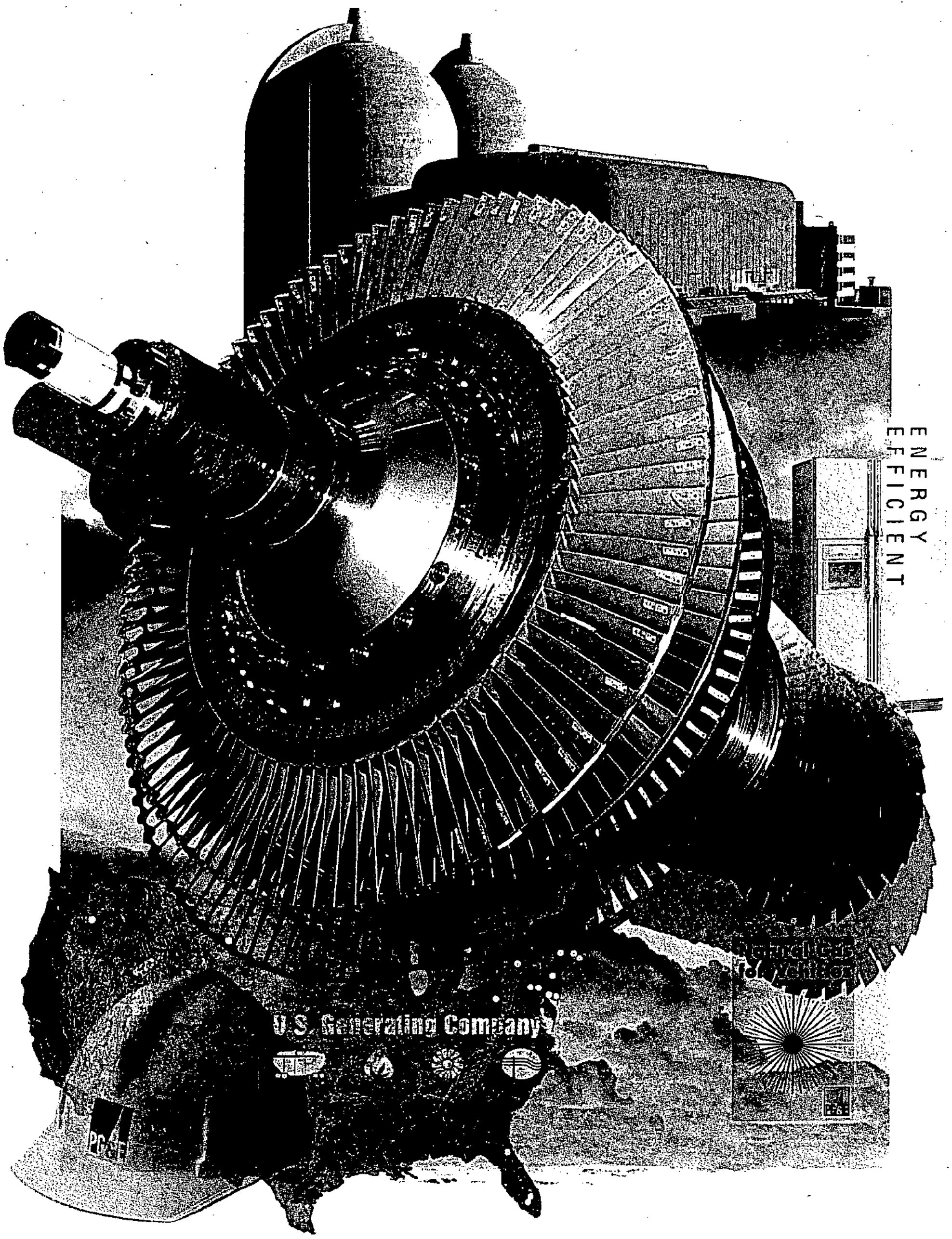
President and
Chief Operating Officer

February 16, 1994

Issue With **competition, lower returns** on utility investment and become more volatile and more difficult to increase.

Action PG&E plans to focus on **six sources of earnings**



slow growth in electric use, earnings in the industry will

through the end of the decade.

Utility. Our utility business serves one of the nation's largest and potentially most dynamic economies. It produces 80 percent of our annual revenues and more than 50 percent of corporate earnings. As our markets change and become more competitive, we will seek every opportunity to add to our earnings from our basic utility business.

Diablo Canyon. In 1993, Diablo Canyon was placed on the Nuclear Regulatory Commission's list of the five best plants in the nation for the fourth consecutive time. Diablo Canyon produced 16.8 billion kilowatthours of electricity. Although both units are scheduled for refueling during the year, the plant is expected to continue to contribute significantly to corporate earnings in 1994.

Under an agreement reached by PG&E, the California Attorney General and the California Public Utilities Commission, the price of Diablo Canyon power after 1994 will be adjusted by a formula based on current inflation. This could slow the rate of future earnings growth from the plant.

Customer Energy Efficiency (CEE). Also contributing to earnings are CEE programs. These conservation efforts allow the company to share in the savings our customers realize as a result of these energy-saving programs. In 1993, these programs resulted in pre-tax earnings of $17 million to be recorded over three years.

Through CEE, which is our least expensive resource alternative, we plan to meet about 75 percent of the growth in peak electric demand by the year 2000.

PG&E Enterprises. Although budgeted only to break even, PG&E Enterprises contributed 4 cents per share to earnings in 1993. This was due to higher natural gas prices and profits from U.S. Generating Company.

U.S. Generating Company, a joint venture with Bechtel Group, Inc., builds and operates unregulated power plants which provide electricity at wholesale to other utilities. U.S. Generating has 11 power plants in operation or construction located in Florida, New Jersey, Pennsylvania, Massachussets and New York. Together, these modern, clean-burning facilities will represent a total of more than 1,700 megawatts and about $320 million in PG&E equity.

Because of the economic slowdown and the impact of programs to reduce demand for electricity through energy efficiency, not as many new power plants are being built in the U.S. today. Accordingly, we are assessing whether to enter the expanding international market.

PG&E Resources, a natural gas and oil exploration and development company, did well in 1993 because of increases in the price and production of gas. However, this appears to be a good time to sell Resources and redeploy the capital to businesses that provide predictable earnings growth.

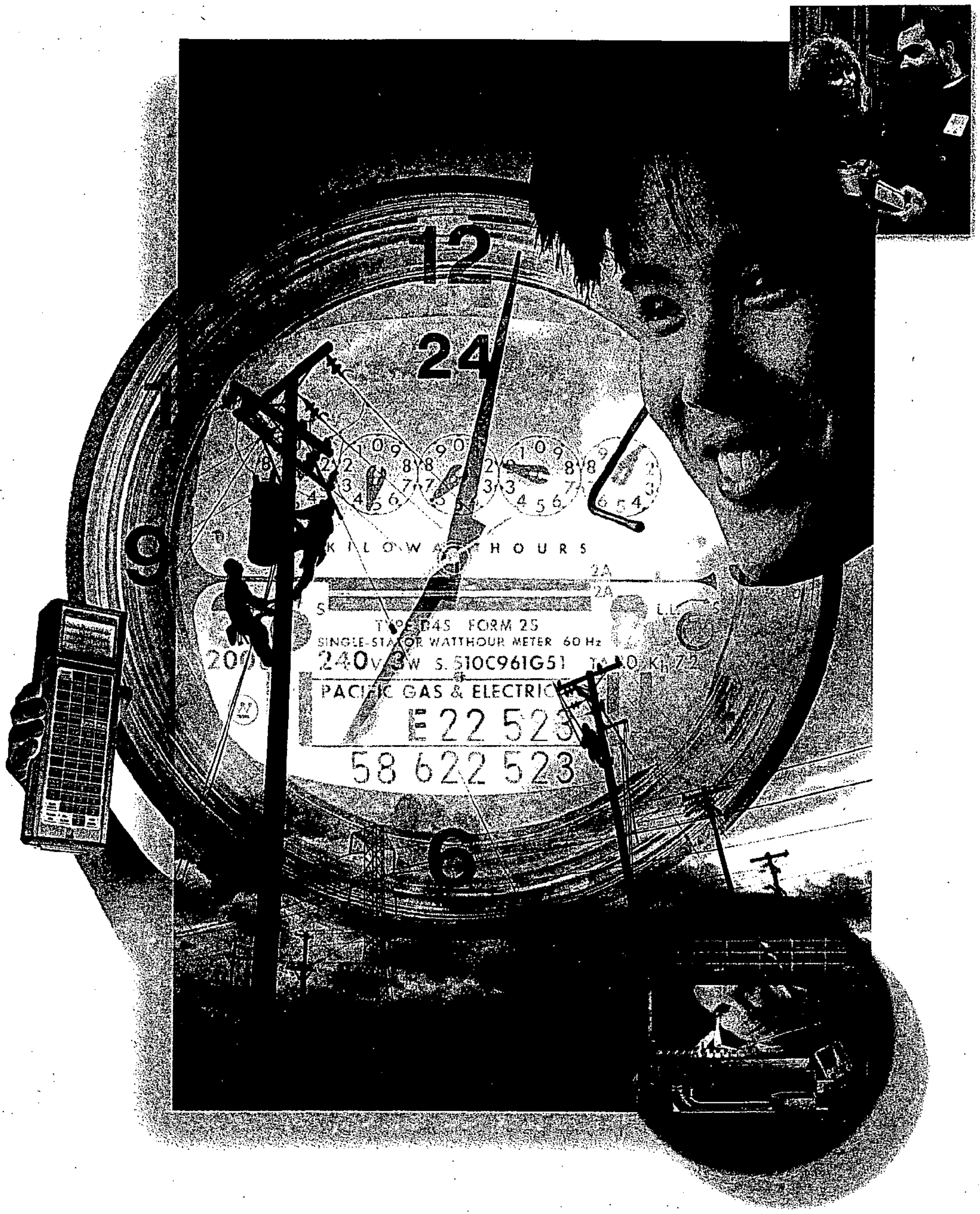
The California real estate market has been depressed for several years, negatively affecting PG&E Properties, our real estate development organization. As a result, PG&E is proceeding with the development and sale of its existing projects, but not adding to its portfolio.

Incentive Ratemaking. We anticipate regulatory changes that will include incentive ratemaking – a system in which our earnings growth would be tied to our performance, not the amount of our capital investment. Our success will depend on meeting or exceeding performance targets by controlling costs and improving productivity. This performance-based proposal is not a new concept for the company: Diablo Canyon operates under a pay-for-performance formula.

New Products And Services. In the longer term, changes in our industry may well offer new opportunities for PG&E to provide new products and services based on the company's experience and expertise. For example, we have entered into an agreement with Tele-Communications Incorporated and Microsoft to test the use of television to provide real-time information to customers in their homes and businesses on their energy use. We continue to work with other companies on a variety of new businesses.

Issue Outstanding companies today **provide added services** t

Action PG&E is **tailoring its service** to meet customers



customers, raising their expectations for all businesses.

diverse energy needs.

As the competition in our industry has intensified, we are working more closely with customers to determine what their specific needs are. We no longer want customers who are merely satisfied; we want customers to say our service is "excellent."

We are installing the latest and most advanced telephone technology to provide around-the-clock, seven-day-a-week service that customers are coming to expect. This improved service will be delivered from new call centers in San Francisco, Sacramento, San Jose and Fresno.

Customer Expectations Differ. Excellent service demands that we approach customers on an individual basis. Using sophisticated, detailed market segmentation, we are gaining in-depth information about the specific needs and priorities of every type of customer that we serve. And customers in these segments – from agriculture to high tech, office buildings to food processors – have very different expectations for utility service.

Price is important to every customer, but it is not the deciding factor for all. What many of our customers want when they call us for service is to have that service provided to their satisfaction the very first time. This has an added benefit. Getting it right the first time means excellent customer service. It also is more efficient and less costly. That is why it is a key service objective for us.

Keeping Major Customers. Other customers have very specific needs. For example, computer and software manufacturers depend heavily on quality and reliability of power, while light industries such as printing and textiles place great value on energy efficiency and options for bill paying.

Today, industrial customers are concerned when their emissions exceed California's stringent air-quality standards. Gallo Glass Company in Modesto was faced with making dramatic reductions in pollution or moving to another state. With the help of PG&E's marketing department, Gallo Glass Company is converting its plant furnaces to a new technology that uses oxygen and natural gas, cutting nitrogen oxide emissions by 79 percent and carbon monoxide by 87 percent.

A research and development grant from PG&E to a joint effort by the Department of Energy, Union Carbide and Corning Glass furthered development of the alternate technology that Gallo Glass will use to produce 2 million bottles a day and employ some 3,000 workers. The company has received nearly $350,000 in PG&E rebates for the furnace conversions.

Energy Is A Significant Business Expense. The sheer size of some facilities makes energy a significant business expense. Super Kmart Center stores, covering 150,000 to 190,000 square feet, are planned for Brisbane, Sanger, Livermore, Oakland and Milpitas this year. All of these "megastores" will have energy-saving measures which earn rebates from PG&E. We have been working with Kmart on building energy efficiency into the five stores being constructed this year as well as four other conventional Kmart Stores planned for Antioch, Ft. Bragg, Taft and McKinleyville.

In highly competitive businesses such as hotel and motel chains, an innovation can take hold across an industry. Marriott Hotels chose not to use fluorescent lighting until recent technical improvements made compact fluorescent lamps comfortable and pleasing for guests. The hotel chain retrofitted guest rooms with energy-efficient lighting in all nine of its Courtyard hotels and three of seven Marriott Hotels in PG&E's territory, earning sizable PG&E rebates. Subsequently, Motel 6 did the same, completing exterior lighting retrofits. Incandescent-to-fluorescent lighting conversions in Motel 6 guest rooms are planned this year. Several Holiday Inns are also planning lighting retrofits.

Issue To succeed, utilities must rigorously **manage costs** to kee

Action Stringent budgeting, refinancing securities are helping **keep PG&E's costs down.**

their prices competitive.

restructuring the work force and adopting new ways of working

In today's energy markets where different customers have different needs, PG&E must have a pricing strategy that satisfies them all. In our industrial markets, where there are alternative suppliers vying for our customers, we must provide competitive prices. But that cannot be done at the expense of customers for whom fewer energy options are available. PG&E's prices must be fair for all customers.

Our per-unit price for electricity – like those of other major investor-owned California utilities – is high compared to the national average because of state policies that have placed an emphasis on clean and renewable generation. We do, however, provide competitive electric prices to major industrial customers that have alternatives to PG&E services. And electricity bills for other customers are below the national average, in part because of energy efficiency in California.

Competitive Gas Prices. Our gas prices are even more competitive, the lowest of all California utilities, comparable to the national average for residential customers, and in the lowest quartile nationally for industrial customers.

Still, we cannot allow our prices – for gas and especially electricity – to increase at the levels they have in the past. To better manage our prices, we are taking additional steps to control the underlying costs.

One of these was a freeze on all retail electric prices announced in April 1993, which will remain in effect throughout this year. This freeze, along with an economic stimulus rate discount offered to major customers, will help PG&E hold the line on prices.

As part of our effort to keep prices down, PG&E took aggressive action to reduce costs throughout the company last year. An important step was the reorganization and downsizing that was completed in 1993. It is projected to provide net savings to our customers of $170 million by the end of 1995. Starting in 1996, these savings are expected to increase to at least $200 million annually. Originally scheduled to be completed in three years, the corporatewide reorganization was achieved in less than one year, primarily through voluntary severance and early retirement incentive packages.

By adopting new technologies that increase the accuracy and efficiency of many tasks, PG&E is able to accomplish all necessary work and continue to improve service, while doing so with a smaller work force.

As industry restructuring moves ahead and the role of utilities further evolves, PG&E will continue to evaluate the work force to ensure that we are doing the jobs we need to do with the right levels of staff.

Refinanced Securities. In another major cost-reduction step, PG&E refinanced $5.2 billion of debt and preferred stock in 1992 and 1993 to take advantage of lower interest rates. These refinancings, which amount to half of PG&E's outstanding debt and preferred stock, will save the company about $94 million a year.

Operating budgets, which have been held essentially flat since 1987, will continue to be rigorously managed. We are increasing efficiency throughout the organization by improving the ways we get the job done.

A systematic approach to changing the way we work is the use of "Action Forums," a process which has been successfully adopted by other competitive companies. Through Action Forums, the employees closest to the work develop and implement ways to be more efficient and productive.

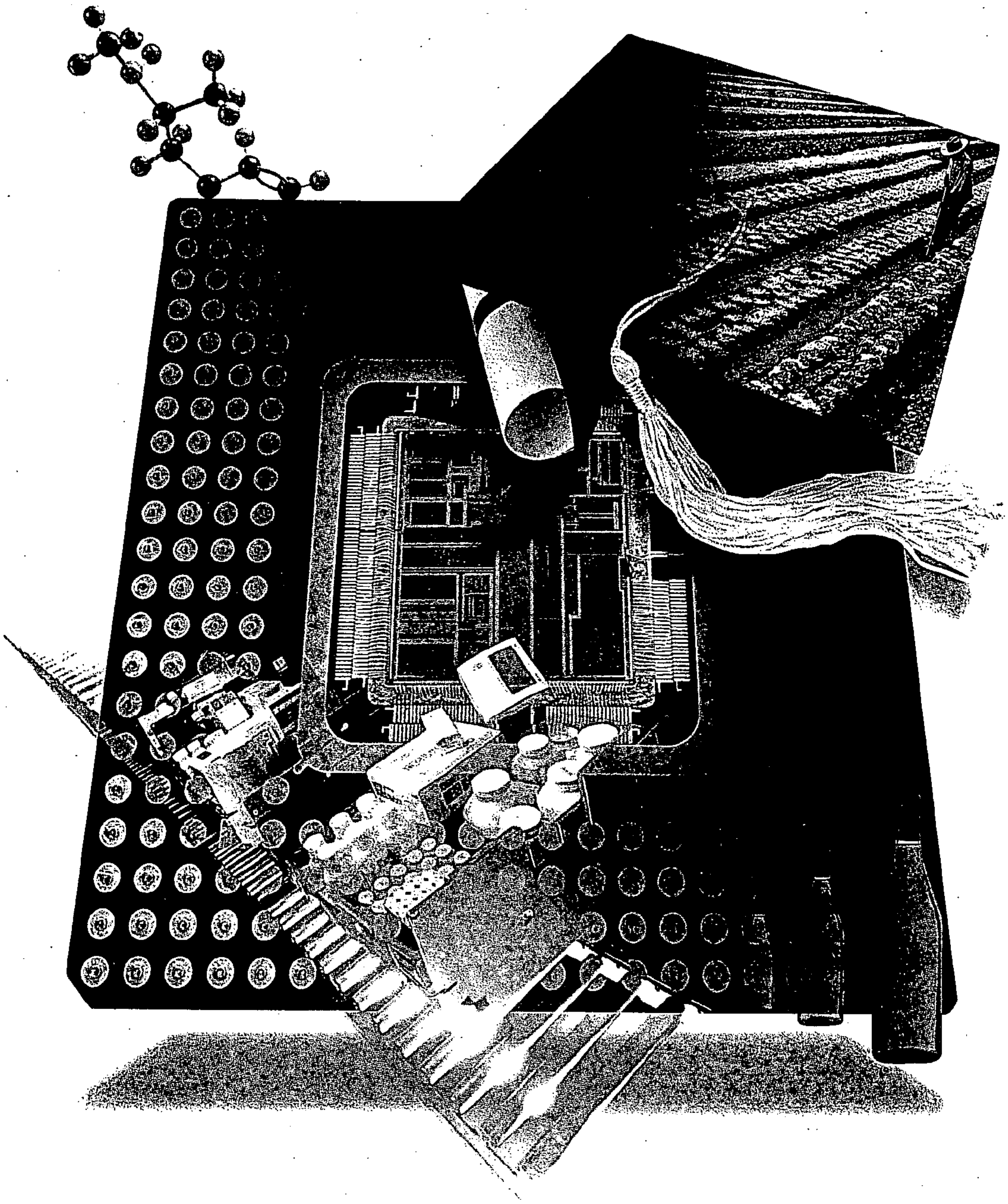
Added Efficiencies. By identifying and putting into use added efficiencies in our material and fleet operations, customer billing system, power generation and transmission departments, among others, the Action Forums have in the past few months identified substantial annual savings.

The Electric Supply and Nuclear Power business units will make significant reductions by holding down the costs of electric supply. And Technical and Construction Services will focus on areas that could result in as much as $150 million in annual savings by 1995. Savings will be realized in numerous ways, including inventory reduction, wider use of prefabricated supplies and further efficiencies in fleet vehicle operations.

Many of the cost reductions are the result of the way PG&E is approaching "reinventing" the corporation. As other aspects of the company's operations are examined, we expect additional operational savings will be identified.

Issue With **California still in a recession**, PG&E must do its par

Action Through **partnerships and innovation**, PG&
California's economic vitality.



t o assist the recovery.

is promoting business development with job growth to improve

Like much of the rest of the nation over the last several years, California has struggled with a major economic downturn. Today, the state faces complex challenges to its future growth and prosperity, including restructuring of many elements of its economy. But the challenges can be overcome as Californians build on the region's enormous strengths – a task PG&E must play a part in.

California is home to 33 percent of the nation's fastest-growing companies. Almost one out of every four of America's fastest-growing small companies is located here. We're the number one manufacturing state, and we're leaders in the entertainment industry and agribusiness.

Northern and Central California where PG&E provides energy have many economic assets. Best known is the Silicon Valley where computer, electronics and biotech industries are concentrated in one of the world's greatest technology centers. They can draw upon cutting edge scientific research conducted at world class universities in the Bay Area, as well as highly educated workers drawn by the region's climate, diversity and beautiful geography.

Partnership For Economic Growth. During the past 90 years, PG&E has played an important part in the growth and prosperity of the communities and companies we serve. Now, when California's economy is troubled, PG&E's role has expanded. We are working to improve the business climate through partnership and innovation.

That partnership begins with service that helps our industrial and commercial customers compete in their markets. We understand their businesses and work to tailor our service with special contracts, as well as energy-efficient technology to help them cut costs.

Whether it's assisting a small furniture refinishing business in meeting environmental compliance regulations, or recommending a massive new cooling system to a large manufacturer, PG&E tries to turn better service into higher profits for all our customers.

With other states trying to convince companies in California to relocate by offering incentive packages, PG&E has developed an "early warning system" to identify customers who are considering leaving and help them find reasons to stay. By actively listening and understanding our customers' concerns, we can help them evaluate alternatives and study options.

For example, a major glass manufacturer was considering leaving the state. PG&E offered energy-saving improvements, efficiency rebates, and short- and long-term price adjustments. The result: The company stayed in California and about 500 jobs were saved. And we preserved about $4 million in annual revenues.

Working To Attract New Business. Another important role for PG&E is to work with state and local governmental agencies, as well as business organizations, to attract new business and retain existing companies in California. In this joint effort, PG&E has proposed competitive rates and energy-efficient technologies to encourage businesses to remain or relocate in our service territory. We vigorously promote Northern and Central California as areas of economic opportunity and growth potential.

This includes active involvement in projects such as Joint Venture: Silicon Valley, a public-private partnership of 1,000 business, government and community leaders in the state's technology capital. The venture's goal is to ensure that the business climate in Silicon Valley remains conducive to leading high-tech companies while making the area an even better place to work and live.

An Unparalleled Opportunity. The success of economic development ventures often requires a break from the past. The closure of military bases throughout California is a difficult but necessary element in the restructuring of the state's economy. But these closures also present us with an unparalleled opportunity because these bases are among some of the state's most desirable property. PG&E is working to ensure that once they are converted, former military bases will contribute to a new, stronger economy by being used for their highest and best purposes.

	1993	1992	1991	1990	1989
(in thousands, except per share amounts)					
For the Year					
Operating revenues	**$ 10,582,408**	$10,296,088	$ 9,778,119	$ 9,470,092	$ 8,588,264
Operating income	**1,762,930**	1,833,441	1,713,079	1,706,136	1,622,558
Net income	**1,065,495**	1,170,581	1,026,392	987,170	900,628
Earnings per common share	**2.33**	2.58	2.24	2.10	1.90
Dividends declared per common share	**1.88**	1.76	1.64	1.52	1.40
At Year End					
Book value per common share	**$ 19.77**	$ 19.41	$ 18.40	$ 17.86	$ 17.38
Common stock price per share	**35.13**	33.13	32.63	25.00	22.00
Total assets	**27,162,526**	24,188,159	22,900,670	21,958,397	21,351,970
Long-term debt and preferred stock with mandatory redemption provision (excluding current portions)	**9,367,100**	8,525,948	8,341,310	7,902,409	7,951,320

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.

Results of Operations

Pacific Gas and Electric Company (PG&E) and its wholly owned and majority-owned subsidiaries (the Company) have three types of operations: utility, Diablo Canyon Nuclear Power Plant (Diablo Canyon) and nonregulated through PG&E Enterprises (Enterprises). For 1993, 1992 and 1991, selected financial information for the three types of operations is shown below:

(in millions, except per share amounts)	Utility	Diablo Canyon[1]	Enterprises	Total
1993				
Operating revenues				
Electric	**$ 5,933**	**$ 1,933**	**$ -**	**$ 7,866**
Gas	**2,465**	**-**	**251**	**2,716**
Total operating revenues	**8,398**	**1,933**	**251**	**10,582**
Operating expenses	**7,335**	**1,225**	**259**	**8,819**
Operating income (loss)	**$ 1,063**	**$ 708**	**$ (8)**	**$ 1,763**
Net income	**$ 552**	**$ 496**	**$ 17**	**$ 1,065**
Earnings per common share	**$ 1.18**	**$ 1.11**	**$ .04**	**$ 2.33**
Total assets at year end	**$ 19,870**	**$ 6,250**	**$1,043**	**$ 27,163**
1992				
Operating revenues				
Electric	$ 5,966	$1,781	$ -	$ 7,747
Gas	2,340	-	209	2,549
Total operating revenues	8,306	1,781	209	10,296
Operating expenses	7,125	1,118	220	8,463
Operating income (loss)	$ 1,181	$ 663	$ (11)	$ 1,833
Net income (loss)	$ 738	$ 443	$ (10)	$ 1,171
Earnings (loss) per common share	$ 1.61	$ .99	$ (.02)	$ 2.58
Total assets at year end	$17,759	$5,494	$ 935	$24,188
1991				
Operating revenues				
Electric	$ 5,868	$1,501	$ -	$ 7,369
Gas	2,336	-	73	2,409
Total operating revenues	8,204	1,501	73	9,778
Operating expenses	6,953	1,004	108	8,065
Operating income (loss)	$ 1,251	$ 497	$ (35)	$ 1,713
Net income (loss)	$ 777	$ 274	$ (25)	$ 1,026
Earnings (loss) per common share	$ 1.71	$ .59	$ (.06)	$ 2.24
Total assets at year end	$16,440	$5,543	$ 918	$22,901

[1] *See Note 3 of Notes to Consolidated Financial Statements for discussion of allocations.*

EARNINGS PER COMMON SHARE: Earnings per common share were $2.33, $2.58 and $2.24 for 1993, 1992 and 1991, respectively. Earnings per common share for 1993 were lower than for 1992 due to charges against earnings of $410 million which were partially offset by Diablo Canyon's performance as discussed in the Operating Revenues section. The above charges are detailed as follows:

Year ended December 31, *(in millions)*	1993
Workforce reduction program costs	**$190**
Gas decontracting costs and reserves for gas transportation commitments	**127**
Reserve for gas reasonableness proceedings	**61**
Diablo Canyon deferred tax liability adjustment	**32**
Total	**$410**

Earnings per common share for 1992 were higher than for 1991 primarily due to one scheduled refueling outage at Diablo Canyon in 1992, compared to two scheduled refueling outages in 1991, and the annual increase in the price per kilowatthour (kWh) as provided in the Diablo Canyon rate case settlement.

In 1993 and 1992, the Company earned an 11.9% and a 13.7% return on average common stock equity, respectively.

COMMON STOCK DIVIDEND: In January 1994, the Company raised the quarterly common stock dividend 4.3%, from an annualized rate of $1.88 per share to $1.96 per share.

The amount of the Company's common stock dividend is based on a number of financial considerations, including sustainability, financial flexibility and competitiveness with investment opportunities of similar risk. Over time, the Company plans to reduce its dividend payout ratio (dividends declared divided by earnings available for common stock) to reflect the increased business risk in the utility industry and the earnings volatility associated with the Diablo Canyon rate case settlement.

OPERATING REVENUES: Electric revenues increased $119 million and $378 million in 1993 and 1992, respectively, compared to the preceding year. The increase in 1993 electric revenues was due to rate increases associated with general increases in operating expenses and a higher electric rate base on which PG&E is allowed to earn a return, as provided in the 1993 General Rate Case (GRC). This increase was offset by a decrease in revenues resulting from a decrease in the cost of electric energy. In addition, Diablo Canyon revenues, which are included in the electric revenues discussed above, increased due to the annual increase in the price per kWh as provided in the Diablo Canyon rate case settlement.

The increase in 1992 electric revenues was primarily due to one scheduled refueling outage at Diablo Canyon in 1992, compared to two scheduled refueling outages in 1991, and the annual increase in the price per kWh as provided in the Diablo Canyon rate case settlement.

Gas revenues increased $167 million and $140 million in 1993 and 1992, respectively, compared to the preceding year. The 1993 increase was primarily due to rate increases associated with general increases in operating expenses and a higher gas rate base on which PG&E is allowed to earn a return, as provided in the 1993 GRC, as well as increased revenues from Enterprises reflecting increases in the price and production of gas.

The 1992 increase was primarily due to revenues resulting from the December 1991 acquisition of Tex/Con Oil & Gas Company (Tex/Con) by PG&E Resources Company (Resources), a wholly owned subsidiary of Enterprises.

OPERATING EXPENSES: In 1993 and 1992, the Company's operating expenses increased $356 million and $398 million, respectively, over the preceding year. The 1993 increase was due to a charge against earnings of $190 million related to the Company's workforce reduction program and increases in administrative and general expense, income tax expense, and depreciation and decommissioning expense of $114 million, $100 million and $94 million, respectively, offset by a decrease of $166 million in the cost of electric energy. Most of the increase in administrative and general expense was due to an increase in litigation costs and an increase in employee costs upon adoption of Statement of Financial Accounting Standards (SFAS) No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." The increase in income tax expense was primarily due to the increase in the federal income tax rate to 35% from 34%, and a related adjustment to Diablo Canyon deferred income tax liability, as required under SFAS No. 109, "Accounting for Income Taxes." The increase in depreciation and decommissioning expense was a result of an increase in depreciation expense related to the increase in plant in service. The decrease in the cost of electric energy was a result of improved hydroelectric conditions and reflects a decline in the cost per kWh for purchased power and a reduction in the volume of gas used to provide electric energy.

The 1992 increase in operating expenses was primarily due to increases in the cost of gas, the cost of electric energy, and depreciation and decommissioning expense. The cost of gas increased in 1992 by $103 million over the preceding year, primarily due to an increase in the cost of gas purchased on behalf of, and transported for, noncore customers. The cost of electric energy increased $98 million in 1992 compared to 1991, primarily due to increases in the cost of purchased power and natural gas. The $81 million increase in depreciation and decommissioning expense reflects an increase in depreciation expense related to the increase in plant in service.

OTHER INCOME AND (INCOME DEDUCTIONS): Total other income was $74 million, $124 million and $95 million for 1993, 1992 and 1991, respectively.

Allowance for equity funds used during construction was $42 million, $39 million and $25 million for 1993, 1992 and 1991, respectively. The increases in 1993 and 1992 compared to the preceding year were primarily due to the PGT-PG&E Pipeline Expansion Project which was put in service in November 1993.

Other – net for 1993 includes amounts recorded for the gas decontracting costs, losses on long-term commitments for gas transportation capacity and a possible disallowance in connection with gas reasonableness proceedings as discussed in the Natural Gas Matters section.

Other – net for 1992 included a $19 million after-tax gain from the sale by Pacific Gas Transmission Company (PGT), a wholly owned gas pipeline subsidiary of the Company, of its 49.98% interest in Alberta Natural Gas Company Ltd (ANG). Other – net for 1992 also reflects the establishment of new accounting guidelines for the recognition of revenues related to customer energy efficiency programs, which resulted in a $25 million decrease in the amount of income recognized in 1992 compared to 1991.

Included in 1991 other – net is the write-off by ANG of its investment in a magnesium metal production facility project in Alberta, Canada. This write-off resulted in a $26 million after-tax charge.

DIABLO CANYON: The Diablo Canyon rate case settlement, which became effective July 1988, bases revenues for the plant 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 the plant because the extent and timing of the recovery of actual operating costs, depreciation and a return on the investment in the plant primarily depend on the amount of power produced and the level of costs incurred. The Company's earnings are affected directly by plant performance and costs incurred.

Diablo Canyon revenues are based primarily on a pre-established price per kWh consisting of a fixed component and an escalating component of electricity generated by the plant. (Pricing for Diablo Canyon is discussed in Note 3 of Notes to Consolidated Financial Statements.) From the revenues received for Diablo Canyon, the Company must recover the costs of owning and operating the plant, including all future capital additions. If power generation drops below specified capacity levels, the Company may request floor payments which ensure that the Company will receive some revenue, even if the plant stops producing power. However, payments received must be refunded to customers under specified conditions. Decommissioning and certain specific costs will continue to be recovered through base rates and are not subject to plant performance.

The plant capacity factors for 1993 and 1992 were 89% and 88%, respectively, reflecting the scheduled refueling outage for Unit 2 in 1993 and Unit 1 in 1992. There were no extended unscheduled outages in 1993 and 1992. Through December 31, 1993, the lifetime capacity factor for the plant was 79%. The Company will report significantly lower revenues for the plant during any extended outages, including refueling outages. Refueling outages, the lengths of which depend on the scope of the work, typically occur for each unit every eighteen months. Refueling outages for Unit 1 and Unit 2 are scheduled to begin in March 1994 and September 1994, respectively, and each is planned to last about nine weeks.

Each Diablo Canyon unit will contribute approximately $3.1 million in revenues per day at full operating power in 1994. Beginning in 1995 and thereafter, the escalating component in the price of Diablo Canyon power provided by the settlement agreement will be based on a formula that will be adjusted by the change in the consumer price index plus 2.5%, divided by two. This could slow the rate of future earnings growth from the plant.

WORKFORCE REDUCTION PROGRAM: In the first quarter of 1993, the Company announced a corporate reorganization and workforce reduction program. As of December 31, 1993, the Company has recorded workforce reduction program costs of $264 million, net of a curtailment gain relating to pension benefits. In April 1993, the Company announced a freeze on electric rates through 1994. As a result, the Company has expensed $190 million of such costs relating to electric operations. The remaining $74 million of such costs relating to gas operations has been deferred for future rate recovery. The amount deferred is currently being amortized as savings are realized. The Company is seeking rate recovery of all costs incurred in connection with the workforce reduction program relating to electric and gas operations.

During 1994 and 1995, the Company expects to benefit from the expense reduction attributable to the electric operations' workforce reduction. The Company currently estimates that the workforce reduction program will result in a net revenue requirement savings of approximately $170 million during the three-year 1993 GRC cycle, which ends December 31, 1995. Beginning in 1996, the workforce reduction program is expected to result in annual revenue requirement savings of at least $200 million. (See Note 8 of Notes to Consolidated Financial Statements for further discussion of the workforce reduction program.)

ELECTRIC RATE INITIATIVE: In April 1993, the Company proposed a comprehensive electric rate initiative to freeze current retail electric rates through the end of 1994 and to reduce electric rates by $100 million for major businesses as an economic stimulus for those customers. In June 1993, the California Public Utilities Commission (CPUC) approved the economic stimulus rate, effective for the period July 1993 through December 1994.

In December 1993, the CPUC approved the electric rate freeze and issued its decision in the Company's Attrition Rate Adjustment (ARA) and the Energy Cost Adjustment Clause (ECAC) proceedings. As part of the ECAC decision, the CPUC approved the Company's request to defer beyond 1994 recovery of a portion of the undercollections in the ECAC balancing account. The total undercollection at December 31, 1993, was $427 million.

Pursuant to the electric rate initiative, the effects of the CPUC decisions on the Company's various electric rate proceedings (including the cost of capital proceeding discussed in the Liquidity and Capital Resources section) were consolidated resulting in a net change in electric rates of zero, effective January 1994.

The Company intends to achieve cost reductions to offset revenue reductions due to the economic stimulus rate. To the extent that these cost reductions are not achieved, there would be a negative impact on the Company's 1994 results of operations.

COMPETITION: The Company is currently experiencing increasing competition in both the gas and electric energy markets. In recent years, changes in governmental regulations, new technology, interest in self-generation and cogeneration, and competition from nonutility and nonregulated energy suppliers have provided many major utility customers with alternative sources to satisfy their gas and electric requirements.

The recent restructuring of the natural gas industry has increased competition. As a result of regulatory changes, the Company no longer provides combined purchase and transportation services to many of its industrial and large commercial customers (noncore customers). Instead, many noncore customers now purchase gas supplies directly from gas shippers or producers, reserve interstate transportation capacity directly from interstate pipelines, and then purchase intrastate transportation service from the Company once their gas arrives at the California border. Furthermore, an interstate pipeline has proposed expanding its facilities into the Company's service territory which, if approved, would allow it to compete directly for intrastate transportation service to the Company's noncore customers. To the extent that regulators approve this pipeline, the Company could lose customers and volume on its gas transportation system.

The restructuring of the natural gas industry has had a significant impact on the Company's gas operations. In 1993, the Company terminated its long-term Canadian gas purchase contracts and has entered into new, more flexible arrangements for the purchase of the Company's current lower gas supply requirements. In addition, the Company is continuing its efforts to permanently assign or broker its commitments for firm gas transportation capacity which it once held for its noncore customers. As a result of these changes, the Company has recorded reserves in 1993 for its transportation commitments. (See Natural Gas Matters section and Note 2 of Notes to Consolidated Financial Statements for further discussion of regulatory restructuring and the impact on the Company's gas purchase and transportation commitments.)

While the restructuring of the electric industry is still evolving, proposals being considered at state and federal levels and the recently enacted National Energy Policy Act of 1992 (Act) are expected to bring more competition into the electric generation business. The Company currently purchases approximately one-third of the electrical power supplied to its customers from generation sources outside the Company's service territory and from qualifying facilities owned and operated by independent power producers. (Qualifying facilities are small power producers or cogenerators that meet certain federal guidelines and thereby qualify to supply generating capacity and electric energy to electric utilities, which must purchase this power at prices approved by state regulatory bodies.) Future additions to satisfy electric supply needs in the Company's service territory will be determined largely through a competitive resource procurement process, a feature of the new competitive market for electric generation. The Company has indicated a willingness to forgo building new generation capacity in its service territory if appropriate regulatory reforms are instituted in the energy procurement process to provide increased procurement flexibility.

With its enactment, the Act reduces various restrictions on the operation and ownership of independent power producers and provides them and other wholesale suppliers and purchasers with increased access to electric transmission lines throughout the United States. The Federal Energy Regulatory Commission (FERC) now has increased authority to order a utility to transport and deliver, or "wheel," energy for wholesale purchasers or sellers of power. While the Act prohibits FERC-ordered retail wheeling, it does not address the states' ability to order retail wheeling. If future restructuring were to include retail wheeling whereby customers purchase energy directly from an independent power producer and separately pay the Company to wheel the purchased power, the Company's power generation plants and resources would be subject to competition from other available supply options.

Under current regulation, customer prices are based on an allocation among customer classes of the Company's approved cost of service revenue requirements. Currently, large industrial and commercial customers are the most likely to have lower cost competitive alternatives. If a substantial number of these customers were to leave the system, the Company's recovery of its investment in production sources and distribution facilities would be dependent on prices charged to remaining customers and the Company's ability to reduce costs. This could lead to lower shareholder returns.

To succeed in this more competitive environment, the Company has taken steps in 1993 to improve service to customers, reduce costs and lower the price of gas and electric service. The Company has:

1) Reduced its workforce by approximately 3,000 positions which will result in net revenue requirement savings of approximately $170 million during the three-year 1993 GRC cycle and annual revenue requirement savings of at least $200 million beginning in 1996. (See the Workforce Reduction Program section and Note 8 of Notes to Consolidated Financial Statements for further discussion of the workforce reduction program.)

2) Reduced its cost of capital by taking advantage of significantly lower interest rates to reduce financing costs. (See the Sources of Capital section for further discussion of debt refinancing.)

3) Obtained CPUC approval to freeze current electric rates through the end of 1994 and to reduce electric rates by $100 million for major businesses over an 18-month period beginning in July 1993. (See the Electric Rate Initiative section for further discussion of the electric rate initiative.)

4) Begun discussions with the CPUC, customers and other interested parties on the Company's regulatory reform initiative which, in part, would allow the Company more flexibility to respond to competitive conditions quickly. (See the Regulatory Reform Initiative section for further discussion of the regulatory reform initiative.)

5) Given discounts on its gas transportation contracts for certain major industrial customers to obtain long-term commitments. To date, customers entering into these contracts represent approximately 12 percent of total noncore transportation volume.

Further, the Company continues to pursue improvements in the efficiency and productivity of its operations and is committed to sustaining high levels of customer service.

REGULATORY REFORM INITIATIVE: In February 1993, the CPUC's Division of Strategic Planning issued its report on electric industry restructuring, which concluded that the current regulatory approach is incompatible with the emerging industry structure resulting from technological change, competitive pressure and new market forces. The CPUC has several proceedings in progress in which it is investigating reform proposals. The Company has begun discussions with the CPUC, customers and other interested parties concerning various reforms to the current regulatory approach to setting rates. Under the traditional regulatory approach, rates generally are based on a detailed examination of the utility's costs of providing service plus a reasonable rate of return. The resulting amount is the utility's revenue requirement, which the Company is permitted to recover in rates. Under the approach being explored by the Company, the Company's revenue requirement would be adjusted annually on the basis of a series of market indices, such as inflation and customer growth, and a productivity factor designed to reflect cost savings from increased efficiency. The Company and its customers would share in savings or excess costs.

This approach would act as a surrogate for detailed cost examinations and would be used to determine the Company's base revenues, intended to recover the Company's fixed costs and nonfuel variable costs and to provide a return on invested capital. Fuel procurement incentives also could be implemented for the Company's gas purchases for core portfolio customers and power plant fuel. This approach would use market-based benchmarks to determine the amount of revenues which the Company could recover to offset these costs, replacing the current after-the-fact reasonableness reviews of those costs by the CPUC.

As part of the Company's proposal for its largest electric customers, the Company is seeking to have increased flexibility to provide discounts and tailor its services to these customers while assuming the risk for decreases in revenues. This change in the cost of service rate approach could result in a change in accounting principle for this customer class. If the accounting criteria applicable to cost of service rate regulation are no longer met, then the Company would write off the allocable share of regulatory assets, including regulatory balancing accounts receivable and those regulatory assets included in deferred charges.

The Company intends to solicit comments from the CPUC, customers and other interested parties and to file a formal application with the CPUC in the first quarter of 1994, with implementation proposed for 1995. To the extent that regulators approve the Company's regulatory reform initiative, changes may occur to the current regulatory framework as discussed below in the Regulatory Matters section.

ACCOUNTING FOR THE EFFECTS OF REGULATION: Based on the regulatory framework in which it operates, the Company currently accounts for the economic effects of regulation in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company is exploring regulatory reforms and expects to file a formal application with the CPUC in 1994. (See the Regulatory Reform Initiative section for further discussion.) If the regulatory reforms contemplated by the Company are adopted, the mechanics of the rate setting process would change. The Company anticipates that rates derived from the regulatory reforms would remain based on cost of service. However, the final determination will be dependent upon the regulatory reform initiative that is ultimately adopted.

In the event that recovery of costs through rates becomes unlikely or uncertain, whether resulting from the expanding effects of competition or specific regulatory actions which force the Company away from cost of service ratemaking, SFAS No. 71 would no longer apply. If the Company were to discontinue application of SFAS No. 71 for some or all of its operations, then it would write off the applicable portion of regulatory assets, including regulatory balancing accounts receivable and those regulatory assets included in deferred charges. The financial effects upon discontinuing application of SFAS No. 71 could be significant.

REGULATORY MATTERS: The Company's electric and gas energy prices are regulated primarily by the CPUC. Base rates compensate the Company for operating and maintenance costs, depreciation and taxes, and provide a return on capital. Base rates are set every three years in GRC proceedings. The base rates for 1993 were established in the 1993 GRC. Between rate cases, the ARA mechanism provides for rate adjustments for inflation, changes in rate base and changes in the authorized cost of capital.

Balancing accounts help stabilize the Company's earnings. The CPUC sets rates based on estimates of future revenues and costs; differences between revenues or energy costs authorized by the CPUC and actual revenues or energy costs are accumulated in the balancing accounts for subsequent rate adjustment. Energy cost balancing accounts (which include ECAC) reduce the effect on earnings of fluctuations in most electric energy and gas costs. Sales balancing accounts (which include Electric Revenue Adjustment Mechanism) reduce the effect on earnings of fluctuations in most sales to electric and gas customers.

Both the ARA mechanism and the energy cost balancing accounts limit the effect of inflation on the Company's earnings from utility operations by closely matching rates with costs.

The regulatory framework for natural gas service (1) segments the Company's gas customers into core (residential and small commercial customers) and noncore classes, (2) provides noncore customers with options in procuring their own gas supplies, (3) allows noncore customers to negotiate interstate gas transportation directly with the interstate pipelines and separately negotiate intrastate gas transportation with their utilities, and (4) places the Company's noncore transportation revenues at increased risk due to competitive alternatives.

Gas cost allocation proceedings allocate forecasted costs between core and noncore customers and set associated rates. This ratemaking mechanism covers a two-year forecast period and includes a balancing account which allows the Company to accumulate 75% of the difference between authorized and actual noncore transportation revenues. Prior to the establishment of the 75% balancing account in May 1992, a 90% balancing account was in effect. As a result, this placed the Company's noncore gas transportation revenues at increased risk to the extent authorized revenues differ from actual.

NATURAL GAS MATTERS: Decontracting Plan: As discussed in Note 2 of Notes to Consolidated Financial Statements, regulatory changes have restructured the natural gas industry. Certain Canadian gas producers filed lawsuits against the Company claiming damages of at least $466 million (Canadian) resulting from the alleged failure of Alberta and Southern Gas Co. Ltd. (A&S), a wholly owned subsidiary of the Company, to meet its minimum contractual gas purchase obligations. A&S, PGT, PG&E and approximately 190 Canadian gas producers subsequently entered into agreements (collectively, the Decontracting Plan) that restructured the Company's Canadian gas supply arrangements. The Decontracting Plan, which became effective November 1, 1993, terminated A&S's contracts with Canadian gas producers and settled all litigation and claims arising from such contracts. The total amount of settlement payments paid to Canadian gas producers pursuant to the Decontracting Plan was approximately $210 million.

In July 1993, FERC approved a transition cost recovery mechanism (TCRM) under which PGT will absorb 25% of approved transition costs, including settlement payments incurred in connection with the termination of A&S's contracts, with the remainder of such costs to be recovered from PGT's shippers.

The Company incurred transition costs of $228 million, consisting of settlement payments made to producers in connection with the implementation of the Decontracting Plan and amounts incurred by A&S in reducing certain administrative and general functions resulting from the restructuring.

Of these costs, the Company deferred $143 million (included in deferred charges – other) for future rate recovery. In addition, the Company recorded a reserve of $31 million due to the uncertainty of A&S's ability to assign or broker its remaining Canadian gas transportation capacity, as costs associated with this capacity are not recoverable as transition costs under the TCRM. Accordingly, the Company expensed $93 million in 1993 and a total of $23 million in prior years.

PGT and PG&E are seeking recovery of all transition costs eligible for recovery under the TCRM other than the 25% of such costs to be absorbed by PGT. While such transition costs are still subject to challenges at the FERC level and the recovery of such costs paid by PG&E as a shipper of gas on PGT's pipelines will depend on the recovery mechanism adopted by the CPUC, the Company believes that it will ultimately recover the deferred transition costs.

Transportation Commitments: As discussed in Note 2 of Notes to Consolidated Financial Statements, PG&E has transportation commitments with several interstate pipeline companies – El Paso Natural Gas Company (El Paso), PGT, and Transwestern Pipeline Company (Transwestern). PG&E's compliance with regulatory changes has resulted in a decrease in the amount of gas required to be purchased by PG&E and a related decrease in the need for firm interstate transportation capacity. Accordingly, PG&E has retained portions of this interstate capacity for its core customers and core subscription customers (noncore customers choosing bundled service) and is brokering or assigning the remaining capacity.

The CPUC has established a mechanism that will allow PG&E to recover demand charges paid to El Paso and PGT in excess of the demand charges for the capacity held for core and core subscription customers, reduced by any revenues received from brokering such capacity, subject to a reasonableness review. With respect to the capacity held by PG&E on Transwestern's pipelines, the CPUC has ordered PG&E to exclude such demand charges from rates pending a reasonableness review.

Gas Reasonableness Proceedings: The CPUC reviews the reasonableness of the Company's gas operations on an annual basis. As part of this review, a CPUC Administrative Law Judge (ALJ) recently issued proposed decisions on the Company's Canadian gas procurement activities and gas inventory operations for 1988 through 1990, recommending disallowances totaling $53 million in gas costs plus interest estimated at approximately $15 million. The ALJ's proposed decisions are not binding and are subject to modification by the CPUC in the final decisions. A final CPUC decision on the Company's Canadian gas procurement activities during 1988 through 1990 is expected in the first quarter of 1994. In reaching this outcome, the ALJ found that the disallowances of up to $670 million which had been recommended by the CPUC's Division of Ratepayer Advocates (DRA) and certain other parties overstated the magnitude of gas cost savings which the Company could have achieved during 1988 through 1990.

The DRA has also contended that the Company overpaid for Canadian gas by $105 million and $61 million in 1991 and 1992, respectively. It is possible that similar issues will be raised regarding the Company's Canadian gas procurement activities during 1993. In addition, the DRA recommended disallowances of $11 million and $31 million for 1991 and 1992, respectively, relating to gas inventory operations and Southwest gas issues.

The DRA also issued a report on its investigation of the operations of A&S and the Company's former affiliate, ANG, recommending a penalty and disallowance of $50 million and $6 million, respectively, for 1988 through 1991. The investigation was initiated in connection with the reasonableness proceeding for 1991. The recommended penalty and disallowance are primarily related to the Company's alleged failure to properly oversee its subsidiaries' activities. In addition, recommendations related to 1992 activities may be made in a subsequent report.

The Company believes that its gas procurement activities, transportation arrangements and operations were prudent and will vigorously contest the disallowances and penalty proposed by the DRA or other parties. However, based on its current assessment of the matter, the Company recorded a reserve of $61 million in 1993 for any disallowance that may be ordered by the CPUC in the gas reasonableness proceedings. The Company currently is unable to estimate the ultimate outcome of the gas reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations. (See Note 2 of Notes to Consolidated Financial Statements for further discussion of gas reasonableness proceedings.)

PGT-PG&E Pipeline Expansion Project: In November 1993, the Company placed in service an expansion of its natural gas transmission system from the Canadian border into California. At December 31, 1993 and 1992, the Company's total investment in the expansion project was approximately $1,587 million (included in plant in service) and $979 million (included in construction work in progress), respectively. The $1,587 million at December 31, 1993, consisted of $767 million for the facilities within California (i.e., intrastate portion) and $820 million for the facilities outside California (i.e., interstate portion).

In February 1994, the CPUC announced a decision on the Company's request for an increase in the California portion of the expansion project's cost cap and its interim rate filing. The CPUC granted the Company's request to increase the cost cap to $849 million but set interim rates based on $736 million, subject to an adjustment based on the outcome of a reasonableness review of capital costs. The CPUC's decision finds that, given market conditions at the time, the Company was reasonable in constructing the expansion project. The CPUC rejected the assignment of costs related to unused capacity on other pipelines (or the Company's intrastate facilities) to the expansion project as previously recommended by an ALJ's proposed decision.

Due to the ratemaking treatment adopted by the CPUC for the California portion of the expansion project, the Company's ability to recover its cost of service rates is contingent upon demand and competitive market pricing for gas transportation services. In light of anticipated demand and pricing in the foreseeable future, the Company has determined that it may not bill its customers to recover its full cost of service (including a return on investment). Consequently, application of SFAS No. 71 was discontinued for the California portion of the expansion project during 1993. This accounting change did not have a significant impact on the Company's financial position or results of operations in 1993.

Based upon the current status of the rate case and market demand, the Company believes it will recover its investment in the expansion project. However, due to the ratemaking adopted by the CPUC and the discontinued application of SFAS No. 71, earnings attributable to the California portion of the expansion project will vary with demand and market pricing. (See the PGT-PG&E Pipeline Expansion Project section of Note 2 of Notes to Consolidated Financial Statements for further discussion.)

LEGAL MATTERS: Antitrust Litigation: In December 1993, the County of Stanislaus, California, and a residential customer of PG&E, filed a complaint against PG&E and PGT on behalf of themselves and purportedly as a class action on behalf of all natural gas customers of PG&E, for the period of February 1988 through October 1993. The complaint alleges that the purchase of natural gas in Canada by A&S was accomplished in violation of various antitrust laws which resulted in increased prices of natural gas for PG&E's customers.

The complaint alleges that the Company could have purchased as much as 50% of its Canadian gas on the spot market instead of relying on long-term contracts and that the damage to the class members is at least as much as the price differential multiplied by the replacement volume of gas, an amount estimated in the complaint as potentially exceeding $800 million. The complaint indicates that the damages to the class could include over $150 million paid by the Company to terminate the contracts with the Canadian gas producers in November 1993. The complaint also seeks recovery of three times the amount of the actual damages pursuant to antitrust laws.

The Company believes the case is without merit and has filed a motion to dismiss the complaint. The Company believes that the ultimate outcome of the antitrust litigation will not have a significant adverse impact on its financial position.

Hinkley Litigation: In 1993, a complaint was filed on behalf of a number 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 the Company's Hinkley Compressor Station, as well as punitive damages.

In 1987, the Company undertook an extensive project to remediate potential groundwater chromium contamination. The Company has incurred substantially all of the costs it currently deems necessary to clean up the affected groundwater contamination. In accordance with the remediation plan approved by the regional water quality control board, the Company will continue to monitor the affected area and perform environmental assessments.

In November 1993, the parties engaged in private mediation sessions. In December 1993, the plaintiffs filed an offer to compromise and settle their claims against the Company for $250 million.

The Company is unable to estimate the ultimate outcome of this matter, but such outcome could have a significant adverse impact on the Company's results of operations. The Company believes that the ultimate outcome of this matter will not have a significant adverse impact on its financial position. (See Note 11 of Notes to Consolidated Financial Statements for further discussion.)

ACCOUNTING PRINCIPLES: Postretirement Benefits Other Than Pensions: SFAS No. 106 established new financial accounting standards which the Company adopted effective January 1, 1993. Due to current regulatory treatment, adoption of SFAS No. 106 did not have a significant impact on the Company's financial position or results of operations.

In 1993, the Company implemented a plan change that will limit the amount it will contribute toward postretirement medical benefits. This limitation, which will take effect for all retirees beginning in 2001, reduces the estimated future annual SFAS No. 106 medical cost by approximately $70 million and the accumulated postretirement obligation for these benefits at July 1, 1993, by approximately $450 million. Due to current regulatory treatment, the limitation did not have a significant impact on the Company's financial position or results of operations. (See Note 7 of Notes to Consolidated Financial Statements for further discussion of postretirement benefits other than pensions.)

Income Taxes: SFAS No. 109 established new financial accounting standards which the Company adopted January 1, 1993. Due to current regulatory treatment, adoption of SFAS No. 109 did not have a significant impact on the Company's results of operations. Adoption of SFAS No. 109 resulted in an increase of $1.8 billion in consolidated liabilities as of January 1, 1993, as a result of recording additional deferred taxes; consolidated assets also increased $1.8 billion, consisting of a $1.5 billion increase in deferred charges (income tax-related deferred charges and Diablo Canyon costs) and a $.3 billion increase in net plant in service. (See Note 9 of Notes to Consolidated Financial Statements for further discussion of income taxes.)

Postemployment Benefits: SFAS No. 112, "Employers' Accounting for Postemployment Benefits," requires employers to adopt accrual accounting for benefits provided to former or inactive employees and their beneficiaries and covered dependents, after employment but before retirement. Due to current regulatory treatment, adoption of SFAS No. 112 in 1994 is not expected to have a significant impact on the Company's financial position or results of operations. (See Note 7 of Notes to Consolidated Financial Statements for further discussion of postemployment benefits.)

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 capital structure provides financial flexibility and access to capital markets at reasonable rates, ensuring the Company's ability to meet all of its capital requirements. As part of its focus on cost reduction, the Company will further reduce financing costs in 1994 by refinancing existing debt and preferred stock with lower-cost issuances.

CPUC Authorized Cost of Capital: In December 1993, the CPUC issued its decision in the Company's 1994 cost of capital proceeding authorizing a utility capital structure and cost as follows:

	Utility Capital Structure	Cost	Weighted Cost
Common equity	47.50%	11.00%	5.22%
Preferred stock	5.50	8.15	.45
Long-term debt	47.00	7.53	3.54
Total authorized return on average utility rate base			9.21%

The authorized return on common equity is a decrease from the 11.90% authorized for 1993. Average utility rate base is projected to be $12.5 billion for 1994.

Debt: In 1993, the Company issued $2,950 million of First and Refunding Mortgage Bonds (series 93A through 93H), $260 million of pollution control revenue bonds and $750 million of medium-term notes. Substantially all the proceeds were used to redeem or repurchase $3,536 million of higher-cost mortgage bonds to accomplish a reduction in financing costs. In December 1993, the Board of Directors (Board) authorized the Company to redeem or repurchase up to $1.2 billion of mortgage bonds, and $125 million of medium-term notes to further reduce financing costs.

The Company issues short-term debt (principally commercial paper) to fund fuel oil, nuclear fuel and gas inventories, and unrecovered balances in balancing accounts. The Company uses external financing when balancing account revenues are under-collected, as in 1993 and 1992, until the revenues, plus interest, are recovered in rates. Short-term debt also has helped fund construction and fluctuations in general working capital. At December 31, 1993, the Company had a $1 billion short-term credit facility, with no borrowings outstanding.

In 1993, PGT finalized a new loan agreement for $710 million. Proceeds were used to finance PGT's portion of the PGT-PG&E Pipeline Expansion Project and to refinance PGT's existing borrowings. As of December 31, 1993, there was $648 million outstanding under this agreement. (See Notes 5 and 6 of Notes to Consolidated Financial Statements for further discussion of long- and short-term debt.)

Equity: In 1993, the Company received $264 million 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 Company issued $200 million of redeemable preferred stock. Proceeds were used to finance a portion of the redemption of $267 million of the Company's higher-cost preferred stock in an effort to reduce financing costs. In December 1993, the Board authorized the Company to redeem or repurchase an additional $175 million of preferred stock. (See Note 4 of Notes to Consolidated Financial Statements for further discussion of preferred stock.)

In July 1993, the Board authorized the Company to reinstate its common stock repurchase program and repurchase up to $1 billion of common stock on the open market or in negotiated transactions over the next three years. This program will be funded by internally-generated funds. Shares will be repurchased to manage the overall balance of common stock in the Company's capital structure. Through December 31, 1993, the Company had repurchased $258 million of its common stock under this program.

CAPITAL REQUIREMENTS: The Company's three-year projection of capital requirements is shown below:

Year ended December 31,	1994	1995	1996
(in millions)			
Utility	$ 1,397	$ 1,319	$ 1,369
Diablo Canyon	105	87	82
Enterprises	227	149	137
Total capital expenditures	1,729	1,555	1,588
Maturing debt and sinking funds	221	514	460
Total capital requirements	$ 1,950	$ 2,069	$ 2,048

The above projection of capital requirements has been reduced from last year's projection to reflect the anticipated reduction in new customer connections and the Company's ongoing cost control efforts. Utility and Diablo Canyon expenditures will be primarily for replacing and enhancing the Company's facilities to improve their efficiency and reliability, to extend their useful lives and to comply with environmental laws and regulations.

Enterprises' actual capital expenditures may vary significantly depending on the availability of attractive investment opportunities. Projected expenditures include oil and gas exploration and development costs for 1994 and Enterprises' equity share of generating facility projects for 1994 through 1996.

In addition to these capital requirements, the Company has other commitments as discussed in Notes 2 and 10 of Notes to Consolidated Financial Statements.

ENVIRONMENTAL MATTERS: The Company is subject to a number of laws and regulations designed to protect human health and the environment by imposing stringent controls with regard to planning and construction activities, land use, air and water pollution and hazardous materials and waste management activities. These laws and regulations affect future planning and existing operations, including environmental protection and remediation activities.

Environmental Protection Measures: 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 $50 million, $50 million and $75 million for 1994, 1995 and 1996, respectively, and are included in the Company's three-year projection table in the above Capital Requirements section. Expenditures during these years will be primarily for nitrogen oxide (NOx) emission reduction projects. The Company currently estimates that compliance with NOx rules could require capital expenditures ranging from $300 million to $500 million to achieve NOx emission reductions over a period of approximately ten years. The Company's environmental protection capital expenditures are generally recovered through rates.

Environmental Remediation: 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. Although the ultimate amount of costs that will be incurred by the Company in connection with its compliance and remediation activities are difficult to estimate due to uncertainty concerning the Company's responsibility and the extent of contamination, the complexity of environmental laws and regulations and the selection of compliance alternatives, the Company has an accrued liability as of December 31, 1993, of $60 million for hazardous waste remediation costs. (See further discussion of the accrued liability for hazardous waste remediation costs and the related deferred charge in Note 11 of Notes to Consolidated Financial Statements.)

SALES AND ACQUISITION: In January 1994, the Company approved a final plan for the disposition of Resources in 1994 if market conditions remain favorable. As of December 31, 1993, Resources had assets of approximately $680 million.

In June 1992, PGT sold its 49.98% interest in ANG for $97 million. The sale resulted in an after-tax gain of $19 million.

In December 1991, Resources purchased Tex/Con, an oil and gas exploration and production company, for $389 million.

Year ended December 31, *(in thousands, except per share amounts)*	**1993**	1992	1991
Operating Revenues			
Electric	**$ 7,866,043**	$ 7,747,492	$7,368,640
Gas	**2,716,365**	2,548,596	2,409,479
Total operating revenues	**10,582,408**	10,296,088	9,778,119
Operating Expenses			
Cost of electric energy	**2,250,209**	2,416,554	2,318,179
Cost of gas	**1,092,055**	1,062,879	960,208
Distribution	**226,975**	219,082	208,881
Transmission	**166,539**	184,165	195,642
Customer accounts and services	**403,560**	421,990	372,088
Maintenance	**442,939**	484,751	525,220
Depreciation and decommissioning	**1,315,524**	1,221,490	1,140,877
Administrative and general	**1,041,453**	927,316	875,878
Workforce reduction costs	**190,200**	–	–
Income taxes	**1,006,774**	906,845	863,089
Property and other taxes	**297,495**	295,164	288,610
Other	**385,755**	322,411	316,368
Total operating expenses	**8,819,478**	8,462,647	8,065,040
Operating Income	**1,762,930**	1,833,441	1,713,079
Other Income and (Income Deductions)			
Interest income	**85,642**	87,244	94,161
Allowance for equity funds used during construction	**41,531**	39,368	24,543
Other – net	**(53,524)**	(3,006)	(23,909)
Total other income and (income deductions)	**73,649**	123,606	94,795
Income Before Interest Expense	**1,836,579**	1,957,047	1,807,874
Interest Expense			
Interest on long-term debt	**731,610**	739,279	697,185
Other interest charges	**118,100**	91,404	101,871
Allowance for borrowed funds used during construction	**(78,626)**	(44,217)	(17,574)
Net interest expense	**771,084**	786,466	781,482
Net Income	**1,065,495**	1,170,581	1,026,392
Preferred dividend requirement	**63,812**	78,887	89,595
Earnings Available for Common Stock	**$ 1,001,683**	$ 1,091,694	$ 936,797
Weighted Average Common Shares Outstanding	**430,625**	422,714	417,965
Earnings Per Common Share	**$2.33**	$2.58	$2.24
Dividends Declared Per Common Share	**$1.88**	$1.76	$1.64

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

Consolidated Balance Sheet

PACIFIC GAS AND ELECTRIC COMPANY

December 31, (in thousands)	1993	1992
ASSETS		
Plant In Service		
Electric		
Nonnuclear	**$ 16,633,772**	$ 16,295,567
Diablo Canyon	**6,518,413**	5,983,976
Gas	**7,146,741**	5,454,084
Total plant in service (at original cost)	**30,298,926**	27,733,627
Accumulated depreciation and decommissioning	**(11,235,519)**	(10,507,560)
Net plant in service	**19,063,407**	17,226,067
Construction Work in Progress	**620,187**	1,534,578
Other Noncurrent Assets		
Oil and gas properties	**573,523**	591,544
Decommissioning and other funds held by trustees	**536,544**	456,061
Other assets	**497,689**	402,041
Total other noncurrent assets	**1,607,756**	1,449,646
Current Assets		
Cash and cash equivalents	**61,066**	97,592
Accounts receivable		
Customers	**1,264,907**	1,319,285
Other	**123,255**	133,826
Allowance for uncollectible accounts	**(23,647)**	(23,806)
Regulatory balancing accounts receivable	**992,477**	743,253
Inventories		
Materials and supplies	**239,856**	234,630
Gas stored underground	**170,345**	151,707
Fuel oil	**109,615**	155,816
Nuclear fuel	**134,411**	135,171
Prepayments	**56,062**	47,809
Total current assets	**3,128,347**	2,995,283
Deferred Charges		
Income tax-related deferred charges	**1,246,890**	–
Diablo Canyon costs	**419,775**	260,042
Unamortized loss net of gain on reacquired debt	**395,659**	289,338
Workers' compensation and disability claims recoverable	**192,203**	174,168
Other	**488,302**	259,037
Total deferred charges	**2,742,829**	982,585
Total Assets	**$ 27,162,526**	$ 24,188,159

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

December 31, *(in thousands)*	1993	1992
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock	**$ 2,136,095**	$ 2,134,228
Additional paid-in capital	**3,666,455**	3,517,062
Reinvested earnings	**2,643,487**	2,631,847
Total common stock equity	**8,446,037**	8,283,137
Preferred stock without mandatory redemption provision	**807,995**	790,791
Preferred stock with mandatory redemption provision	**75,000**	146,888
Long-term debt	**9,292,100**	8,379,060
Total capitalization	**18,621,132**	17,599,876
Other Noncurrent Liabilities		
Customer advances for construction	**152,872**	175,451
Workers' compensation and disability claims	**157,000**	139,000
Other	**246,950**	172,607
Total other noncurrent liabilities	**556,822**	487,058
Current Liabilities		
Short-term borrowings	**764,163**	1,131,124
Long-term debt	**221,416**	353,692
Accounts payable		
Trade creditors	**472,985**	529,315
Other	**389,065**	372,157
Accrued taxes	**303,575**	237,305
Deferred income taxes	**315,584**	326,219
Interest payable	**82,105**	87,975
Dividends payable	**203,923**	187,721
Other	**487,809**	377,186
Total current liabilities	**3,240,625**	3,602,694
Deferred Credits		
Deferred income taxes	**3,978,950**	1,780,769
Deferred investment tax credits	**410,969**	473,879
Other	**354,028**	243,883
Total deferred credits	**4,743,947**	2,498,531
Commitments and Contingencies (Notes 2, 10 and 11)		
Total Capitalization and Liabilities	**$27,162,526**	$24,188,159

Statement of Consolidated Cash Flows

PACIFIC GAS AND ELECTRIC COMPANY

Year ended December 31, *(in thousands)*	1993	1992	1991
Cash Flows From Operating Activities			
Net income	**$ 1,065,495**	$ 1,170,581	$ 1,026,392
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and decommissioning	**1,315,524**	1,221,490	1,140,877
Amortization	**135,808**	121,795	103,923
Gain on sale of investment in Alberta Natural Gas Company Ltd	**–**	(48,722)	–
Deferred income taxes and investment tax credits – net	**319,198**	164,457	60,376
Allowance for equity funds used during construction	**(41,531)**	(39,368)	(24,543)
Net effect of changes in operating assets and liabilities			
Accounts receivable	**64,790**	39,922	(69,076)
Regulatory balancing accounts receivable	**(218,553)**	(215,195)	202,401
Inventories	**23,097**	(7,161)	(7,440)
Accounts payable	**(39,422)**	(102,559)	172,245
Accrued taxes	**44,638**	128,243	35,977
Other working capital	**108,873**	(36,117)	36,784
Other deferred charges	**(158,725)**	8,147	(68,905)
Other noncurrent liabilities	**50,279**	31,374	75,889
Other deferred credits	**110,145**	73,259	9,795
Other – net	**13,184**	49,891	30,382
Net cash provided by operating activities	**2,792,800**	2,560,037	2,725,077
Cash Flows From Investing Activities			
Construction expenditures	**(1,763,024)**	(2,307,318)	(1,753,609)
Allowance for borrowed funds used during construction	**(78,626)**	(44,217)	(17,574)
Purchase of subsidiary	**–**	–	(388,662)
Nonregulated expenditures	**(234,221)**	(148,226)	(117,847)
Proceeds from sale of investment in Alberta Natural Gas Company Ltd	**–**	97,251	–
Other – net	**9,992**	82,352	33,156
Net cash used by investing activities	**(2,065,879)**	(2,320,158)	(2,244,536)
Cash Flows From Financing Activities			
Common stock issued	**264,489**	296,653	271,482
Common stock repurchased	**(257,780)**	(5,410)	(337,969)
Preferred stock issued	**200,001**	195,451	–
Preferred stock redeemed	**(302,640)**	(276,806)	(123,667)
Long-term debt issued	**4,584,548**	1,676,513	738,649
Long-term debt matured or reacquired	**(4,002,704)**	(1,409,337)	(263,220)
Short-term debt issued (redeemed) – net	**(366,961)**	121,213	(14,278)
Dividends paid	**(857,515)**	(809,108)	(765,543)
Other – net	**(24,885)**	(28,736)	10,078
Net cash used by financing activities	**(763,447)**	(239,567)	(484,468)
Net Change in Cash and Cash Equivalents	**(36,526)**	312	(3,927)
Cash and Cash Equivalents at January 1	**97,592**	97,280	101,207
Cash and Cash Equivalents at December 31	**$ 61,066**	$ 97,592	$ 97,280
Supplemental disclosures of cash flow information			
Cash paid for			
Interest (net of amounts capitalized)	**$ 642,712**	$ 694,512	$ 723,968
Income taxes	**542,827**	682,809	768,097

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

(in thousands, except shares)	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, 1990	$2,101,095	$3,170,890	$2,234,227	$7,506,212	$ 983,961	$129,510
Net income – 1991			1,026,392	1,026,392		
Common stock issued (10,263,302 shares)	51,317	220,165		271,482		
Common stock repurchased (12,910,487 shares)	(64,553)	(98,455)	(174,961)	(337,969)		
Preferred stock redeemed (3,811,325 shares)		(5,287)	(4,438)	(9,725)	(89,064)	(24,878)
Cash dividends declared						
Preferred stock			(91,501)	(91,501)		
Common stock			(685,341)	(685,341)		
Other			1,774	1,774		
Net change	(13,236)	116,423	71,925	175,112	(89,064)	(24,878)
Balance December 31, 1991	2,087,859	3,287,313	2,306,152	7,681,324	894,897	104,632
Net income – 1992			1,170,581	1,170,581		
Common stock issued (9,453,353 shares)	47,267	249,386		296,653		
Common stock repurchased (179,610 shares)	(898)	(2,450)	(2,062)	(5,410)		
Preferred stock issued (8,000,000 shares)		(4,549)		(4,549)	125,000	75,000
Preferred stock redeemed (9,365,449 shares)		(12,638)	(14,940)	(27,578)	(229,106)	(20,122)
Cash dividends declared						
Preferred stock			(81,393)	(81,393)		
Common stock			(744,277)	(744,277)		
Other			(2,214)	(2,214)		
Net change	46,369	229,749	325,695	601,813	(104,106)	54,878
Balance December 31, 1992	2,134,228	3,517,062	2,631,847	8,283,137	790,791	159,510
Net income – 1993			**1,065,495**	**1,065,495**		
Common stock issued (7,708,512 shares)	**38,541**	**225,948**		**264,489**		
Common stock repurchased (7,334,876 shares)	**(36,674)**	**(63,180)**	**(157,926)**	**(257,780)**		
Preferred stock issued (8,000,000 shares)					**200,001**	
Preferred stock redeemed (8,156,968 shares)		**(13,375)**	**(21,958)**	**(35,333)**	**(182,797)**	**(84,510)**
Cash dividends declared						
Preferred stock			**(62,521)**	**(62,521)**		
Common stock			**(811,196)**	**(811,196)**		
Other			**(254)**	**(254)**		
Net change	**1,867**	**149,393**	**11,640**	**162,900**	**17,204**	**(84,510)**
Balance December 31, 1993	**$ 2,136,095**	**$ 3,666,455**	**$ 2,643,487**	**$ 8,446,037**	**$ 807,995**	**$ 75,000**

[1] *Includes current portion.*

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

Material Redacted

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December 31, *(dollars in thousands, except per share amounts)*	**1993**	1992
Common Stock Equity		
Common stock, par value $5 per share (authorized 800,000,000 shares, issued and outstanding 427,219,205 and 426,845,569)	**$ 2,136,095**	$ 2,134,228
Additional paid-in capital	**3,666,455**	3,517,062
Reinvested earnings	**2,643,487**	2,631,847
Total common stock equity	**8,446,037**	8,283,137
Preferred Stock		
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 8.2% – 26,534,958 and 18,534,959 shares outstanding	**663,374**	463,373
9% to 10.28% – 0 and 7,311,868 shares outstanding	**–**	182,797
Total preferred stock without mandatory redemption provision	**807,995**	790,791
Preferred stock with mandatory redemption provision		
Par value $25 per share [1]		
6.57% – 3,000,000 shares outstanding	**75,000**	75,000
Par value $100 per share (authorized 10,000,000 shares)		
9% and 10.17% – 0 and 845,100 shares outstanding	**–**	84,510
Total preferred stock with mandatory redemption provision	**75,000**	159,510
Less preferred stock with mandatory redemption provision – current portion	**–**	12,622
Preferred stock with mandatory redemption provision in total capitalization	**75,000**	146,888
Preferred stock in total capitalization	**882,995**	937,679
Long-Term Debt		
Pacific Gas and Electric Company (PG&E)		
First and refunding mortgage bonds		
Maturity — Interest rates		
1993-1998 — 4.25% to 13%	**577,931**	1,034,214
1999-2005 — 5.5% to 9.375%	**1,886,328**	1,840,611
2006-2012 — 6.25% to 10.07%	**477,870**	852,870
2013-2019 — 7.5% to 12.75%	**140,900**	852,196
2020-2026 — 5.85% to 9.95%	**2,947,428**	2,044,950
Principal amounts outstanding	**6,030,457**	6,624,841
Unamortized discount net of premium	**(71,817)**	(103,707)
Total mortgage bonds	**5,958,640**	6,521,134
Unsecured debentures, 10.81% to 12%, due 1994-2000	**221,523**	221,523
Pollution control loan agreements, variable rates, due 2008-2016	**925,000**	925,000
Unsecured medium-term notes, 4.13% to 10.1%, due 1993-2013	**1,542,625**	847,361
Unamortized discount related to unsecured medium-term notes	**(3,459)**	(3,289)
Other long-term debt	**24,127**	26,056
Total PG&E long-term debt	**8,668,456**	8,537,785
Long-term debt of subsidiaries	**845,060**	194,967
Total long-term debt of PG&E and subsidiaries	**9,513,516**	8,732,752
Less long-term debt – current portion	**221,416**	353,692
Long-term debt in total capitalization	**9,292,100**	8,379,060
Total Capitalization	**$18,621,132**	$ 17,599,876

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

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

(in thousands)	Electric	Gas	Diversified Operations[4]	Intersegment Eliminations	Total
1993					
Operating revenues	**$ 7,866,043**	**$ 2,466,788**	**$ 249,577**	**$ –**	**$ 10,582,408**
Intersegment revenues[1]	**15,369**	**223,443**	**5,079**	**(243,891)**	**–**
Total operating revenues	**$ 7,881,412**	**$ 2,690,231**	**$ 254,656**	**$ (243,891)**	**$ 10,582,408**
Depreciation and decommissioning	**$ 925,673**	**$ 251,490**	**$ 138,361**	**$ –**	**$ 1,315,524**
Operating income before income taxes[2]	**2,344,796**	**440,323**	**(7,375)**	**(8,040)**	**2,769,704**
Construction expenditures[3]	**929,065**	**954,116**	**–**	**–**	**1,883,181**
Identifiable assets[3]	**$ 19,125,555**	**$ 6,467,424**	**$1,053,027**	**$ –**	**$ 26,646,006**
Corporate assets					**516,520**
Total assets at year end					**$ 27,162,526**
1992					
Operating revenues	$ 7,747,492	$ 2,342,202	$ 206,394	$ –	$ 10,296,088
Intersegment revenues[1]	15,150	410,014	28,191	(453,355)	–
Total operating revenues	$ 7,762,642	$ 2,752,216	$ 234,585	$ (453,355)	$ 10,296,088
Depreciation and decommissioning	$ 856,124	$ 231,443	$ 133,923	$ –	$ 1,221,490
Operating income before income taxes[2]	2,308,828	441,612	(9,808)	(346)	2,740,286
Construction expenditures[3]	1,124,368	1,266,535	–	–	2,390,903
Identifiable assets[3]	$ 17,658,656	$ 5,068,213	$ 996,860	$ –	$ 23,723,729
Corporate assets					464,430
Total assets at year end					$ 24,188,159
1991					
Operating revenues	$ 7,368,640	$ 2,341,054	$ 68,425	$ –	$ 9,778,119
Intersegment revenues[1]	15,043	541,963	39,958	(596,964)	–
Total operating revenues	$ 7,383,683	$ 2,883,017	$ 108,383	$ (596,964)	$ 9,778,119
Depreciation and decommissioning	$ 843,768	$ 214,488	$ 82,621	$ –	$ 1,140,877
Operating income before income taxes[2]	2,271,571	336,754	(31,227)	(930)	2,576,168
Construction expenditures[3]	1,192,570	603,156	–	–	1,795,726
Identifiable assets[3]	$ 17,253,156	$ 4,212,764	$ 469,222	$ –	$ 21,935,142
Corporate assets					965,528
Total assets at year end					$ 22,900,670

(1) Intersegment electric and gas revenues are accounted for at tariff rates prescribed by the CPUC.

(2) Income taxes and general corporate expenses are allocated in accordance with FERC Uniform System of Accounts and requirements of the CPUC. Operating income in the Statement of Consolidated Income is net of utility income taxes.

(3) Includes an allocation of common plant in service and allowance for funds used during construction.

(4) Includes the nonregulated operations of wholly owned subsidiaries including PG&E Enterprises, Mission Trail Insurance Ltd. (liability insurance), Pacific Gas Properties Company (real estate development), and Pacific Conservation Services Company (conservation loans).

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

Note 1 – Summary of Significant Accounting Policies

REGULATION: Pacific Gas and Electric Company (PG&E) is regulated by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). PG&E's consolidated financial statements reflect the ratemaking policies of these commissions in conformity with generally accepted accounting principles for rate-regulated enterprises. In the Notes to Consolidated Financial Statements, regulated operations other than the Diablo Canyon Nuclear Power Plant (Diablo Canyon) are referred to as the utility.

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements include PG&E and its wholly owned and majority-owned subsidiaries (the Company). All significant intercompany transactions have been eliminated.

Major subsidiaries, all of which are wholly owned, are: Pacific Gas Transmission Company (PGT) – transports natural gas from the U.S./Canadian border to PG&E at the California border; Alberta and Southern Gas Co. Ltd. (A&S) – prior to November 1, 1993, bought gas in Canada and arranged transport to the U.S. border (see Note 2 for discussion of the restructuring of A&S's operations); Pacific Energy Fuels Company – finances the purchase of nuclear fuel through issuance of its commercial paper; PG&E Enterprises (Enterprises) – the parent company for nonregulated subsidiaries, including PG&E Resources Company (Resources), which engages in exploration, development and production of oil and natural gas, and PG&E Generating Company which develops independent power projects.

Alberta Natural Gas Company Ltd (ANG), a 49.98%-owned affiliate of PGT, was sold in June 1992. ANG, a Canadian pipeline company, transported natural gas for A&S to the U.S. border. Prior to the sale of ANG, the Company's investment in ANG was accounted for by the equity method of accounting.

REVENUES: Revenues are recorded primarily for deliveries of gas and electric energy to customers. These revenues give rise to receivables from a diversified base of customers including residential, commercial and industrial customers in Northern and Central California.

The CPUC has established mechanisms known as balancing accounts which help stabilize the Company's earnings. Specifically, sales balancing accounts accumulate differences between authorized and actual base revenues. Energy cost balancing accounts accumulate differences between actual costs of gas and electric energy and the revenue 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 2 for further discussion of gas costs.) These balancing accounts are recorded to the extent that future rate recovery from customers, or refunds to customers, are probable.

PLANT IN SERVICE: The costs of plant additions, including replacements of retired plant, are capitalized. Costs include labor, materials, construction overheads and an allowance for funds used during construction (AFUDC). AFUDC is the cost of debt and equity funds used to finance the construction of new facilities. Financing costs of capital additions for Diablo Canyon and the California portion of the PGT-PG&E Pipeline Expansion Project are calculated under Statement of Financial Accounting Standards (SFAS) No. 34, "Capitalization of Interest Cost," since Diablo Canyon and the California portion of the PGT-PG&E Pipeline Expansion Project are not on traditional cost-based ratemaking. (See Notes 2 and 3 for further discussion of these matters.) These costs are included in allowance for borrowed funds used during construction. The original cost of retired plant plus removal costs less salvage are charged to accumulated depreciation. Maintenance, repairs and minor replacements and additions are charged to maintenance expense.

DEPRECIATION AND DECOMMISSIONING: Depreciation of plant in service is computed using a straight-line remaining-life method.

The estimated cost of decommissioning the Company's nuclear power facilities is recovered in base rates through an annual allowance. For the year ended December 31, 1993, 1992 and 1991, the amounts recovered in rates for decommissioning costs were $54 million, $54 million, and $65 million, respectively. The estimated total obligation for decommissioning costs is approximately $1 billion in 1993 dollars; this obligation is being recognized ratably over the facilities' lives. This estimate considers the total 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.

As of December 31, 1993 and 1992, the Company had accumulated in external trust funds $537 million and $456 million, respectively, to be used for the decommissioning of the Company's nuclear facilities; corresponding amounts are thus included in accumulated depreciation and decommissioning. These trust funds maintain substantially all of their investments in debt securities. All fund earnings are reinvested. At December 31, 1993 and 1992, the estimated fair values of the external trust funds were approximately $576 million and $475 million, respectively, based on quoted market prices. Funds may not be released from the external trust funds until authorized by the CPUC.

As required by federal law, the U.S. Department of Energy (DOE) is responsible for the future storage and disposal of spent nuclear fuel. The cost of these activities is funded through a one-tenth of one cent fee on each kilowatthour (kWh) sold by all nuclear power plants. This fee is paid quarterly to the DOE.

INCOME TAXES: The Company files a consolidated federal income tax return that includes domestic subsidiaries in which its ownership is 80% or more. Income tax expense includes the current and deferred income tax expense resulting from operations during the year. Investment tax credits are deferred and amortized to income over the life of the related property.

Effective January 1, 1993, the Company adopted SFAS No. 109, "Accounting for Income Taxes," which established new financial accounting standards for income taxes. SFAS No. 109 prohibits net-of-tax accounting, requires that deferred tax liabilities and assets be adjusted for enacted changes in the income tax rates and requires the use of the liability method of accounting for income taxes. Under the liability method, the deferred tax liability represents the tax effect of temporary differences between the financial statement and income tax bases of assets and liabilities at the currently enacted income tax rates. Temporary differences are measured at the balance sheet date, resulting in adjustments to the deferred tax liability and related deferred charge, consistent with the ratemaking process.

The effect of the adoption of SFAS No. 109, as of January 1, 1993, was an increase of $1.8 billion in consolidated liabilities as the result of recording additional deferred taxes; consolidated assets also increased $1.8 billion, consisting of a $1.5 billion increase in deferred charges (income tax-related deferred charges and Diablo Canyon costs) and a $.3 billion increase in net plant in service. These adjustments relate to temporary differences, which prior to adoption of SFAS No. 109 were not recorded as deferred taxes, consistent with the ratemaking process. These differences included removal costs and federal tax depreciation on property acquired prior to 1981, depreciation differences for state purposes, percentage repair allowances expensed for tax purposes and certain capitalized overheads expensed for tax purposes. Due to current regulatory treatment, the adoption of SFAS No. 109 did not have a significant impact on the Company's results of operations.

During 1993, the Omnibus Budget Reconciliation Act of 1993 (Act) was enacted, which included an increase in the corporate federal income tax rate to 35% from 34%. Due to current regulatory treatment, the Company recorded a deferred charge for the adjustment of deferred income taxes related to utility operations as a result of this increase. Since Diablo Canyon is not on traditional cost-based ratemaking, a one-time adjustment to income tax expense of $32 million resulted. The Act did not have a significant impact on the Company's results of operations during 1993.

DEBT PREMIUM, DISCOUNT AND RELATED EXPENSE: Long-term debt premium, discount and related expense are amortized over the life of each issue. Gains and losses on reacquired debt allocated to the utility are amortized over the remaining original lives of the debt reacquired, consistent with ratemaking; gains and losses on debt allocated to Diablo Canyon and the California portion of the PGT-PG&E Pipeline Expansion Project are recognized in income at the time such debt is reacquired.

OIL AND GAS PROPERTIES: Resources uses the successful-efforts method of accounting for oil and gas properties.

INVENTORIES: Nuclear fuel inventory is stated at the lower of average cost or market. Amortization of 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 (at cost which approximates market) include special deposits, working funds and short-term investments with original maturities of three months or less.

RECLASSIFICATIONS: Prior years' amounts in the consolidated financial statements have been reclassified where necessary to conform to the 1993 presentation.

Note 2 – Natural Gas Matters

REGULATORY RESTRUCTURING: The CPUC has established a regulatory framework for natural gas service in California which segments customers into core (residential and smaller commercial customers) and noncore (industrial and commercial customers that exceed certain size limitations) classes. This framework allows noncore customers to purchase gas directly from producers, aggregators or marketers and separately negotiate gas transportation with their utilities. The CPUC has also adopted a capacity brokering program which allows noncore customers and other shippers to obtain rights to firm interstate pipeline transportation capacity held by the local gas distribution utilities. Under the capacity brokering program implemented August 1, 1993, the Company is required to make available for brokering all interstate pipeline capacity which is not retained for its core customers and core subscription customers (noncore customers choosing bundled service). Noncore customers, producers, aggregators, marketers and the Company's electric department can bid for such capacity.

In addition, in April 1992, FERC issued Order 636 which requires interstate pipelines to restructure their services. This order unbundled sales, transportation and storage services, instituted capacity release programs and provided for recovery of transition costs related to the restructuring of services.

The Company's compliance with these regulatory changes has allowed many of the Company's noncore customers to arrange for the purchase and transportation of their own gas supplies. These changes have resulted in a decrease in the amount of gas required to be purchased by the Company and a related decrease in the need for firm transportation capacity and have contributed to the need to restructure the Company's gas supply arrangements.

Decontracting Plan: Until November 1993, PG&E purchased Canadian natural gas from PGT which in turn purchased such gas from A&S. A&S had commitments to purchase minimum quantities of natural gas from approximately 190 Canadian gas producers under various long-term contracts, most of which extended through 2005. Certain of these Canadian gas producers filed lawsuits against the Company claiming damages of at least $466 million (Canadian) resulting from the alleged failure of A&S to meet its minimum contractual gas purchase obligations. As a result of the regulatory restructuring discussed above, A&S, PGT, PG&E and approximately 190 Canadian gas producers entered into agreements (collectively, the Decontracting Plan) which terminated A&S's contracts with these Canadian gas producers and settled all litigation and claims arising from such contracts. Under the Decontracting Plan which became effective November 1, 1993, producers' contracts with A&S, the sales agreement between A&S and PGT, and PG&E's service agreement with PGT were terminated, allowing producers to decontract their reserves from the A&S supply pool. As a result, PG&E may contract on an individual basis for its gas supply requirements directly with any producer, aggregator or marketer, whether or not they were formerly in the A&S supply pool.

Under the Decontracting Plan, producers released A&S, PGT and PG&E from any claims they may have had that resulted from the termination of the former arrangements as well as any claims for losses arising from alleged historical shortfalls in gas taken by A&S. The total amount of settlement payments paid to producers was approximately $210 million.

As part of the overall A&S decontracting process, A&S's operations have been significantly reduced, with a major aggregator of Canadian natural gas acquiring A&S's restructured gas purchase contracts and remaining sales contracts. A&S continues to hold gas transportation capacity on Canadian pipelines and is in the process of permanently assigning or brokering such capacity.

As part of the Decontracting Plan, A&S permanently assigned portions of its commitments for transportation capacity with NOVA Corporation of Alberta (NOVA) through October 2001 and ANG through October 2005 to third parties. A&S also assigned approximately 600 million cubic feet per day (MMcf/d) of capacity on each of these pipelines to PG&E for use in the servicing of PG&E's core and core subscription customers. A&S currently holds the remaining capacity of approximately 450 MMcf/d with annual demand charges of approximately $25 million for which it is continuing its efforts to assign or broker. There is uncertainty about the ability of A&S to assign or broker this remaining capacity. To the extent others do not take this capacity, A&S will remain obligated to pay for the related demand charges.

In July 1993, FERC approved a transition cost recovery mechanism (TCRM) for PGT under which most costs which were incurred to restructure, reform or terminate the sales arrangements between A&S and PGT and underlying A&S gas supply contracts, or to resolve claims by gas suppliers related to past or future liabilities or obligations of PGT or A&S, are eligible for recovery in PGT's rates. The TCRM precludes most objections to the eligibility and prudence of such costs; prudence challenges may be made only on the grounds that the payment is unreasonably high in light of the damages claimed. Disposition of approved transition costs will be as follows: (1) 25% of such costs will be absorbed by PGT; (2) 25% will be recovered by PGT through direct bills (substantially all to PG&E as PGT's principal customer); and (3) 50% will be recovered by PGT through volumetric surcharges over a three-year period. Costs associated with A&S's commitments for Canadian pipeline capacity do not qualify as transition costs recoverable under this mechanism.

Financial Impact of Decontracting Plan and Litigation: The Company incurred transition costs of $228 million, consisting of settlement payments made to producers in connection with the implementation of the Decontracting Plan and amounts incurred by A&S in reducing certain administrative and general functions resulting from the restructuring. Of these costs, the Company deferred $143 million (included in deferred charges – other) for future rate recovery. In addition, the Company recorded a reserve of $31 million due to the uncertainty of A&S's ability to assign or broker its remaining commitments for Canadian transportation capacity. Accordingly, the Company expensed $93 million in 1993 and a total of $23 million in prior years.

PGT and PG&E are seeking recovery of all transition costs eligible for recovery under the TCRM other than the 25% of such costs to be absorbed by PGT. While such transition costs are still subject to challenges at the FERC level and the recovery of such costs paid by PG&E as a shipper of gas on PGT's pipelines will depend on the recovery mechanism adopted by the CPUC, the Company believes that it will ultimately recover the deferred transition costs.

Transportation Commitments: The Company 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 the Company will pay each year may change due to changes in tariff rates and may be reduced to the extent the Company can broker or assign any unused capacity. In addition to demand charges, the Company is required to pay transportation charges for actual quantities shipped. The Company's total demand and transportation charges paid under these agreements (excluding PGT) were approximately $280 million in 1993, $300 million in 1992 and $260 million in 1991.

As discussed above, regulatory changes have resulted in a decrease in the amount of gas required to be purchased by the Company and a related decrease in the need for firm transportation capacity. The Company has retained portions of this capacity to be used for its core and core subscription customers and has permanently assigned significant portions of the remaining capacity. The following table summarizes the approximate amounts of capacity held by the Company on various pipelines for its core and core subscription customers and capacity remaining to be assigned or brokered as of December 31, 1993:

Pipeline Company	Amount Held for Core (MMcf/d)	Remaining Amount Available for Brokering (MMcf/d)	Total Annual Demand Charges (in millions)	Contract Expiration
El Paso	610	530	$130	Dec. 1997
PGT	610	430	$ 50	Oct. 2005
Transwestern	50*	150	$ 30	Mar. 2007
NOVA	610	460	$ 35	Oct. 2001
ANG	600	440	$ 20	Oct. 2005

* *This amount is held by the Company's electric department for electric power generation.*

The Company expects to recover the demand charges associated with capacity held for its core and core subscription customers through its gas balancing account mechanisms. The CPUC has established a separate mechanism that will allow PG&E to recover the demand charges paid to PGT and El Paso Natural Gas Company (El Paso) in excess of the demand charges for the capacity held for core and core subscription customers, reduced by revenues received from brokering such capacity, subject to a reasonableness review. With respect to Transwestern Pipeline Company (Transwestern) capacity, which the Company contracted in order to provide supply diversity and reliability and to stimulate price competition, the CPUC has ordered the Company to exclude such demand charges from rates pending a reasonableness review.

The Company is continuing its efforts to broker or assign the remaining transportation capacity that is not used. During the latter half of 1993, as implementation of capacity brokering began on interstate pipelines – El Paso, PGT and Transwestern – PG&E has been able to broker a significant portion of the unused capacity, including limited amounts of that held for its core and core subscription customers when such capacity was not being used. Amounts brokered have been on a short-term basis, most of which were at a discounted price. The average monthly demand charges associated with the Company's unused interstate capacity have been approximately $10 million, of which the Company has been able to recover approximately 50% through capacity brokering during the past few months. Because the success of the Company's brokering efforts will depend on market demand, the Company cannot predict the volume or the price of the capacity that will be brokered in the future.

GAS REASONABLENESS PROCEEDINGS: Recovery of gas costs through the Company's regulatory balancing account mechanisms is subject to a CPUC determination that such costs were incurred reasonably. Under the current regulatory framework, annual reasonableness proceedings are conducted by the CPUC on a historic calendar year basis.

1988-1990: The CPUC consolidated its review of the reasonableness of gas system costs for 1988 through 1990. A CPUC Administrative Law Judge (ALJ) recently issued proposed decisions on the Company's Canadian gas procurement activities and gas inventory operations during 1988 through 1990.

The proposed decision on the Company's Canadian gas procurement activities finds that the Company's procurement practices were reasonable in light of the events and circumstances then applicable, but that the Company was imprudent to the extent that it failed to take reasonable steps to bargain more aggressively with Canadian gas suppliers. The proposed decision recommends a disallowance of approximately $46 million of gas costs plus accrued interest estimated at approximately $15 million. The proposed decision also finds that the disallowances recommended by the CPUC's Division of Ratepayer Advocates (DRA) and an intervenor overstate the magnitude of savings which the Company could have achieved during 1988 through 1990. The DRA had recommended that the Company refund $392 million based on its contention that the Company should have purchased 50% of its Canadian supplies on the spot market instead of almost totally relying on long-term contracts. Using a different theory than the DRA, an intervenor had asserted that the Company overpaid for Canadian gas in the range of $540 million to $670 million.

In the proposed decision on gas inventory operations, the ALJ found the Company's gas inventory operations in 1989 and 1990 to be reasonable except for operations during December 1990 for which the ALJ proposed a disallowance of $7 million. Earlier, the DRA recommended a disallowance of $37 million contending that the Company should have withdrawn additional gas from storage in the winter of 1989-1990 and December 1990 rather than burning fuel oil, which was more expensive.

A final CPUC decision on the Company's Canadian gas procurement activities is expected in the first quarter of 1994. CPUC consideration of other issues which relate to purchased electric energy and certain contracts with Southwestern gas producers has been deferred. Relating to purchased electric energy costs, the DRA recommended a disallowance of $18 million contending that had the Company purchased lower cost Canadian gas, the Company would have realized a reduction in its electric energy costs. However, the DRA has not yet addressed issues related to certain contracts with Southwestern gas producers.

1991: The DRA has issued a report on the reasonableness of the Company's gas procurement and operating activities for 1991. The DRA recommended that the Company refund approximately $116 million, consisting of $105 million related to Canadian gas purchases and $11 million related to gas inventory operations and Southwest gas procurement issues. The DRA's recommendations are based on the same theories outlined in the DRA's reports for 1988 through 1990, as discussed above.

1992: The DRA issued a report on the reasonableness of the Company's gas procurement and operating activities for 1992, recommending that the Company refund approximately $92 million. The recommended disallowance includes $61 million related to Canadian gas purchases and $8 million related to gas inventory operations, based on the same theories outlined in prior DRA reports. Also included are disallowances totaling $23 million related to Southwest gas transportation and procurement issues. It is possible that similar issues will be raised regarding the Company's Canadian gas procurement activities during 1993. However, the Company estimates the disallowance that the DRA may recommend for 1993 should be significantly lower than those for prior years.

Affiliate Audit: The DRA issued a report on its investigation of the operations of A&S and the Company's former affiliate, ANG, for 1988 through 1991. The investigation was initiated in connection with the reasonableness proceeding for 1991. The DRA reviewed certain nongas costs, primarily Canadian pipeline charges and A&S overhead costs, and recommended a penalty and disallowance of $50 million and $6 million, respectively. The recommended penalty and disallowance are primarily related to the Company's alleged failure to properly oversee its subsidiaries' activities. In addition, recommendations related to 1992 activities may be made in a subsequent report. The Company filed a motion with the CPUC asking it to disregard the recommended penalty and disallowance because prior federal rulings approved such costs and thus preempt the issue. In December 1993, an ALJ denied this motion.

Financial Impact of Gas Reasonableness Proceedings: The DRA is a consumer advocacy branch of the CPUC staff. Neither the DRA's recommendations nor the ALJ's proposed decisions constitute a CPUC decision. The CPUC can accept all, part or none of the DRA's recommendations or the ALJ's proposed decisions. The Company believes that its gas procurement activities, transportation arrangements and operations were prudent and will vigorously contest the disallowances and penalty proposed by the DRA or other parties. However, based on its current assessment of the matter, the Company recorded a reserve of $61 million in 1993 for any disallowance that may be ordered by the CPUC in the gas reasonableness proceedings. The Company currently is unable to estimate the ultimate outcome of the gas reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations.

PGT-PG&E PIPELINE EXPANSION PROJECT: In November 1993, the Company placed in service an expansion of its natural gas transmission system from the Canadian border into California. The pipeline provides an additional 148 MMcf/d of firm capacity to the Pacific Northwest and an additional 755 MMcf/d of firm capacity to Northern and Southern California. At December 31, 1993 and 1992, the Company's total investment in the expansion project was approximately $1,587 million (included in plant in service) and $979 million (included in construction work in progress), respectively. The $1,587 million at December 31, 1993, consisted of $767 million for the facilities within California (i.e., intrastate portion) and $820 million for the facilities outside California (i.e., interstate portion).

The construction of facilities within the state of California has been certificated by the CPUC. The conditions of the certificate place the Company at risk for its decision to construct based on its assessment of market demand and subsequent underutilization of the facility. The certificate requires the application of a "cross-over" ban under which volumes delivered from the incremental interstate (PGT) expansion must be transported at an incremental expansion rate within California. Incremental rate design is based on the concept that expansion shippers, not existing ratepayers, bear the incremental costs of the expansion project. Capacity on the interstate portion is fully subscribed under long-term firm transportation contracts. However, to date, shippers have only executed long-term firm transportation contracts for approximately 40% of the intrastate capacity. The CPUC has authorized the Company to provide as-available service on the expansion project, which would provide additional revenues to recover the incremental costs of the expansion project. The Company continues negotiations for the remaining capacity.

The CPUC certificate issued in December 1990 established a cost cap of $736 million for the California portion, which represented the maximum amount determined by the CPUC to be reasonable and prudent based on an estimate of the anticipated construction costs at that time. In October 1993, the CPUC issued a decision granting the Company's motion to put in place temporary interim rates based on the existing cost cap of $736 million. The decision authorized the temporary interim rates to become effective on the date of commercial operation, November 1, 1993, and remain in effect for five months or until interim rates are established by the CPUC.

In February 1994, the CPUC announced a decision on the Company's request for an increase in the California portion of the expansion project's cost cap and its interim rate filing. The CPUC granted the Company's request to increase the cost cap to $849 million but set interim rates based on $736 million, subject to an adjustment based on the outcome of a reasonableness review of capital costs. The CPUC's decision finds that, given market conditions at the time, the Company was reasonable in constructing the expansion project. The CPUC rejected the assignment of costs related to unused capacity on other pipelines (or the Company's intrastate facilities) to the expansion project as previously recommended by an ALJ's proposed decision.

Due to the ratemaking treatment adopted by the CPUC for the California portion of the expansion project, the Company's ability to recover its cost of service rates is contingent upon demand and competitive market pricing for gas transportation services. In light of anticipated demand and pricing in the foreseeable future, the Company has determined that it may not bill its customers to recover its full cost of service. Consequently, application of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" was discontinued for the California portion of the expansion project during 1993. This accounting change was implemented using the guidelines contained in SFAS No. 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" and did not have a significant impact on the Company's financial position or results of operations in 1993.

Financial Impact of PGT-PG&E Pipeline Expansion Project: Based upon the current status of the rate case and market demand, the Company believes it will recover its investment in the expansion project.

Note 3 – Diablo Canyon

RATE CASE SETTLEMENT: The Diablo Canyon rate case settlement, effective July 1988, bases revenues primarily on the amount of electricity generated by the plant, rather than on traditional cost-based ratemaking. In approving the settlement, the CPUC explicitly stated that it affirmed that Diablo Canyon costs and operations should no longer be subject to CPUC reasonableness reviews. The CPUC cannot bind future commissions in fixing just and reasonable rates for Diablo Canyon, but to the extent permitted by law intends that this decision remain in effect for the full term of the settlement, ending 2016.

The settlement provides that certain Diablo Canyon costs be recovered over the term of the settlement, including a full return on such costs, through base rates. The related revenues to recover these costs are included in Diablo Canyon operating revenues for reporting purposes. Other than these and decommissioning costs, Diablo Canyon no longer meets the criteria for application of SFAS No. 71. Consequently, application of this statement was discontinued for Diablo Canyon effective July 1988.

PRICING: Under the Diablo Canyon rate case settlement, the price per kWh of electricity generated by Diablo Canyon consists of a fixed and an escalating component. The total prices for 1991 through 1993 were 9.60 cents, 10.34 cents and 11.16 cents per kWh, respectively, effective January 1. The total price for 1994, effective January 1, is 11.89 cents per kWh. For 1995 through 2016, the escalating component will be adjusted by the change in the consumer price index plus 2.5%, divided by two. During the first 700 hours of full-power operation for each unit during the peak period (10 a.m. to 10 p.m. on weekdays in June through September), the price is 130% of the stated amount to encourage the Company to utilize the plant during the peak period. Beginning in January of each year, during the first 700 hours of full-power operation for each unit outside the peak period, the price is 70% of the stated amount. At all other times, the price is 100% of the stated amount.

FINANCIAL INFORMATION: Selected financial information for Diablo Canyon is shown below:

Year ended December 31,	**1993**	1992	1991
(in millions)			
Operating revenues	**$1,933**	$1,781	$1,501
Operating income	**708**	663	497
Net income	**496**	443	274

In determining operating results of Diablo Canyon, operating revenues were specifically identified pursuant to the Diablo Canyon rate case settlement. The majority of operating expenses were also specifically identified, including income tax expense. Administrative and general expense, principally labor costs, is allocated based on a study of labor costs. Interest is charged based on an allocation of corporate debt to Diablo Canyon.

Note 4 – Preferred Stock

Nonredeemable preferred stock ($25 par value) consists of 5%, 5.5% and 6% series, which have rights to annual dividends per share of $1.25, $1.375 and $1.50, respectively.

Redeemable preferred stock without a mandatory redemption provision (4.36% to 8.2%, $25 par value) is subject to redemption, in whole or in part, if the Company pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share range from $1.09 to $2.05, and from $25.75 to $28.125, respectively. The 6.57% series ($25 par value) preferred stock is subject to a mandatory redemption provision and is entitled to a sinking fund providing for the retirement of stock outstanding, beginning in 2002, at par value per share plus accumulated and unpaid dividends through the redemption date. In addition to mandatory redemptions, this stock may be redeemed at the Company's option at par value per share plus accumulated and unpaid dividends through the redemption date and a redemption premium under specified circumstances after July 2002. The estimated fair value for the Company's preferred stock with a mandatory redemption provision at December 31, 1993 and 1992, was approximately $81 million and $168 million, respectively, based primarily on quoted market prices.

During 1993, the Company issued $125 million of 6.875% redeemable preferred stock and $75 million of 7.04% redeemable preferred stock. Proceeds were used to finance a portion of the 1993 redemption of all the Company's 9.00%, 9.30%, 9.48% and 10.17% redeemable preferred stock with an aggregate par value of $267 million.

During 1992, the Company issued $125 million of 7.44% redeemable preferred stock and $75 million of 6.57% preferred stock with a mandatory redemption provision, and redeemed the 9.28%, 10.18% and 10.28% series of redeemable preferred stock with an aggregate par value of $229 million.

Dividends on preferred stock are cumulative. Preferred dividends are accrued based on declaration date, whereas preferred dividend requirement, which is used to calculate earnings per common share, is based on the accumulated dividends on preferred stock outstanding at year end. All shares of preferred stock have equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Company, holders of the preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

Note 5 – Long-term Debt

MORTGAGE BONDS: The First and Refunding Mortgage Bonds of the Company are issued in series, bear annual interest rates ranging from 4.25% to 12.75% and mature from 1994 to 2026. The Company had $6.0 billion and $6.6 billion of mortgage bonds outstanding at December 31, 1993 and 1992, respectively. Additional bonds may be issued, subject to CPUC approval, up to a maximum total outstanding of $10 billion, assuming compliance with indenture covenants for earnings coverage and property available as security. The Company's Board of Directors may increase the amount authorized, subject to CPUC approval. The indenture requires that net earnings excluding depreciation and interest be equal to or greater than 1.75 times the annual interest charges on the Company's mortgage bonds outstanding. All real properties and substantially all personal properties of PG&E are subject to the lien of the indenture.

The Company 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. The payments equal .5% of the aggregate bonded indebtedness outstanding on the preceding November 30 and May 31, respectively. Bonds of any series, with certain exceptions, may be used to satisfy this requirement. In addition, holders of series 84D bonds maturing in 2017 have an option to redeem their bonds in 1995.

In conjunction with the Company's focus on reducing the levels of high-cost debt, the Company redeemed or repurchased $3,536 million and $1,182 million of higher-cost mortgage bonds in 1993 and 1992, respectively. Interest rates on the bonds redeemed or repurchased ranged from 7.50% to 12.75%.

During 1993, the Company issued $2,950 million of First and Refunding Mortgage Bonds, series 93A through 93H, with interest rates ranging from 5.375% to 7.250% and maturity dates ranging from 1998 to 2026. Substantially all the proceeds from these bonds were used to redeem or repurchase higher-cost mortgage bonds.

Included in the total of outstanding mortgage bonds are First and Refunding Mortgage Bonds issued by the Company to secure its obligation to repay various loans from the California Pollution Control Financing Authority (CPCFA) to finance air and water pollution control, and sewage and solid waste disposal facilities. The amounts loaned to the Company by the CPCFA consist of proceeds from the CPCFA's sale of tax-exempt pollution control revenue bonds having the same principal amounts and terms as the Company's mortgage bonds securing the loans. At December 31, 1993 and 1992, the Company had outstanding $768 million and $508 million, respectively, of mortgage bonds securing loans from the CPCFA. These mortgage bonds have interest rates ranging from 5.85% to 8.875% and maturity dates from 2007 to 2023.

POLLUTION CONTROL LOAN AGREEMENTS: In addition to the pollution control loans secured by the Company's mortgage bonds (described above), the Company had loans totaling $925 million at December 31, 1993 and 1992, from the CPCFA to finance air and water pollution control, and sewage and solid waste disposal facilities. Interest rates on the loans vary depending on whether the loans are in a daily, weekly, commercial paper or fixed rate mode. Conversions from one mode to another take place at the Company's option. Average annual interest rates on these loans for 1993 ranged from 2.31% to 2.54%. These loans are subject to redemption on demand by the holder under certain circumstances. The Company's obligations for such demands are secured by irrevocable letters of credit which mature as early as 1996.

MEDIUM-TERM NOTES: The Company had $1,543 million and $847 million of unsecured medium-term notes outstanding at December 31, 1993 and 1992, respectively, with interest rates ranging from 4.13% to 10.10% and maturities from 1994 to 2013. During 1993 and 1992, the Company issued $750 million and $263 million of medium-term notes, respectively. Proceeds from these notes were applied to construction expenditures and to the redemption, repurchase or retirement of debt or preferred stock.

LONG-TERM DEBT OF SUBSIDIARIES: In 1993, PGT finalized a new loan agreement for $710 million to finance PGT's portion of the PGT-PG&E Pipeline Expansion Project and to refinance PGT's existing borrowings. As of December 31, 1993, there was $648 million outstanding under this agreement. The loan is secured by PGT's operating revenues and gas transportation contracts. The loan will mature no later than 2004, however, if certain terms and conditions are not met by November 1996, the loan could mature as early as 1997. If early maturity does not occur, a reserve sufficient to cover a minimum of six months of debt service must be established. At December 31, 1993, the Company was in compliance with all terms and conditions. The interest rate varies depending on the rate selected by the Company, which can be the prime rate, London Interbank Offered Rate or certificate of deposit rate, plus applicable margin. During 1993, the weighted average rate of interest was 3.83%.

REPAYMENT SCHEDULE: At December 31, 1993, the Company's combined aggregate amount of maturing long-term debt and sinking fund requirements, for the years 1994 through 1998, are $221 million, $514 million, $460 million, $369 million and $714 million, respectively.

FAIR VALUE: The estimated fair value for the Company's total long-term debt of $9.5 billion and $8.7 billion at December 31, 1993 and 1992, respectively, was approximately $9.9 billion and $9.2 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). Debt allocated to Diablo Canyon at December 31, 1993 and 1992, had a book value of $2.2 billion, and a fair value of approximately $2.3 billion.

Note 6 – Short-term Borrowings

Short-term borrowings consist of commercial paper with a weighted average interest rate of 3.43% at December 31, 1993. The usual maturity for commercial paper is 10 to 90 days. Commercial paper outstanding at December 31, 1993 and 1992, was $764 million and $916 million, respectively. The carrying amount of short-term borrowings approximates fair value.

The Company has a $1 billion revolving credit facility with various banks to support the sale of commercial paper and for other corporate purposes. At December 31, 1993 and 1992, there were no borrowings outstanding under this facility. This credit facility expires in November 1997; however, it may be extended annually for additional one-year periods upon mutual agreement between the Company and the banks. The Company is in compliance with all covenants associated with the facility.

Note 7 – Employee Benefit Plans

RETIREMENT PLAN: The Company provides a noncontributory defined benefit pension plan covering substantially all employees. The retirement benefits are based on years of service and the employee's base salary. The Company's funding policy is to contribute each year not more than the maximum amount deductible for federal income tax purposes and not less than the minimum contribution required under the Employee Retirement Income Security Act of 1974. The cost of this plan is charged to expense and to plant in service through construction work in progress.

Net pension cost, using the projected unit credit actuarial cost method, was:

Year ended December 31,	**1993**	1992	1991
(in thousands)			
Service cost for benefits earned	**$ 129,166**	$ 127,388	$ 112,940
Interest cost	**268,698**	248,674	238,153
Actual return on plan assets	**(511,526)**	(204,576)	(774,445)
Net amortization and deferral	**177,597**	(78,560)	552,775
Net pension cost	**$ 63,935**	$ 92,926	$ 129,423

The decrease in net pension cost in 1993 compared to 1992 was primarily due to a change in the expected long-term rate of return on plan assets to better reflect actual and expected earnings on the funds invested. The decrease in net pension cost in 1992 compared to 1991 was mostly due to favorable investment returns in 1991.

The expected long-term rate of return on plan assets used to calculate pension cost was 9% for 1993, and 8% for 1992 and 1991.

Net pension 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 pension cost. In 1993 and 1991, actual return on plan assets exceeded expected return whereas, in 1992, actual return on plan assets was less than expected return.

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 contribution approach.

The plan's funded status was:

December 31,	**1993**	1992
(in thousands)		
Actuarial present value of benefit obligations		
Vested benefits	**$(3,203,408)**	$(2,680,364)
Nonvested benefits	**(154,349)**	(183,971)
Accumulated benefit obligation	**(3,357,757)**	(2,864,335)
Effect of projected future compensation increases	**(577,926)**	(859,764)
Projected benefit obligation	**(3,935,683)**	(3,724,099)
Plan assets at market value	**4,376,110**	3,872,374
Plan assets in excess of projected benefit obligation	**440,427**	148,275
Unrecognized prior service cost	**117,312**	71,324
Unrecognized net gain	**(759,690)**	(383,498)
Unrecognized net obligation	**120,253**	137,763
Accrued pension liability	**$ (81,698)**	$ (26,136)

The increase in unrecognized prior service cost in 1993 compared to 1992 reflects a plan amendment which provides an increase in benefits to certain retirees.

Plan assets consist substantially of common stocks, fixed-income securities and real estate investments. The unrecognized prior service cost is amortized over approximately 16 years. The unrecognized net obligation is being 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.

Assumptions used to calculate the projected benefit obligation to determine the plan's funded status were:

December 31,	**1993**	1992
Weighted average discount rate	**7%**	7%
Average rate of projected future compensation increases	**5%**	6%

SAVINGS FUND PLAN: The Company sponsors a defined contribution pension plan to which employees with at least one year of service may make contributions. Employees may contribute up to 14 percent and, effective January 1994, 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 Company contributions at specified rates. The cost of Company contributions was charged to expense and to plant in service through construction work in progress and totaled $36 million, $35 million and $33 million for 1993, 1992 and 1991, respectively.

LONG-TERM INCENTIVE PROGRAM: The Company 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 the Company's 1986 Stock Option Plan.

A total of 14.5 million shares of common stock have been authorized for award under the Program and the 1986 Stock Option Plan. Costs associated with the Program, which have not been significant, are not recoverable in rates.

At December 31, 1993, stock options on 1,973,161 shares, granted at option prices ranging from $16.75 to $33.38, were outstanding. During 1993, 691,200 options were granted at an option price of $33.13. Option prices are 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. Stock options also become exercisable within certain time limitations upon the optionee's termination due to retirement, disability, death or a change in control of a subsidiary, and upon certain changes in control of the Company.

In 1993, stock options on 174,387 shares were exercised at option prices ranging from $16.75 to $33.13. At December 31, 1993, stock options on 493,989 shares were exercisable.

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS: The Company 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 the Company's retirees.

The Company's funding policy for the medical and life insurance benefits is to contribute each year the tax-deductible amount provided for in rates. Life insurance benefits which are not funded are provided through an insurance company at a cost based on total current claims paid plus administrative fees. The cost of these plans is charged to expense and to plant in service through construction work in progress.

Effective January 1, 1993, the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," which requires accrual of the expected cost of these benefits during the employees' years of service. The assumptions and calculations involved in determining the accrual closely parallel pension accounting requirements. The Company previously recognized these costs as benefits were paid and funded, which was consistent with ratemaking.

In December 1992, the CPUC issued a decision in the final phase of the investigation on the ratemaking treatment for these benefits in 1993 and beyond. The decision authorized recovery of these benefits, within certain guidelines, at a level equal to the lesser of the annual SFAS No. 106 cost, based on amortization of the transition obligation over 20 years, or the amount which can be contributed annually on a tax-deductible basis to appropriate trusts. Due to this regulatory treatment, adoption of SFAS No. 106 did not have a significant impact on the Company's financial position or results of operations.

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

Year ended December 31,	1993
(in thousands)	
Service cost for benefits earned	$ 38,496
Interest cost	73,502
Actual return on plan assets	(23,999)
Amortization of transition obligation	39,620
Net amortization and deferral	(3,390)
Net postretirement benefit cost	$124,229

The medical and life insurance plans' funded status was:

December 31,	1993
(in thousands)	
Accumulated postretirement benefit obligation	
Retirees	$(384,706)
Other fully eligible participants	(148,018)
Other active plan participants	(365,786)
Total accumulated postretirement benefit obligation	(898,510)
Plan assets at market value	345,938
Accumulated postretirement benefit obligation in excess of plan assets	(552,572)
Unrecognized net loss	21,481
Unrecognized transition obligation	543,939
Prepaid postretirement benefit	$ 12,848

Plan assets consist substantially of common stocks and fixed-income securities. In accordance with SFAS No. 106, the Company elected to amortize the actuarially-determined transition obligation at January 1, 1993, of $1,018 million over 20 years beginning in 1993. In 1993, the Company implemented a plan change that will limit the amount it will contribute toward postretirement medical benefits. This limitation, which will take effect for all retirees beginning in 2001, reduced the accumulated postretirement obligation for these benefits at July 1, 1993, by approximately $450 million. Due to current regulatory treatment, the limitation did not have a significant impact on the Company's financial position or results of operations.

The expected long-term rate of return on plan assets used to calculate postretirement medical and life insurance benefit costs for 1993 was 9%. The assumptions used to calculate the benefit obligations included a weighted average discount rate of 7% and a rate of projected future compensation increases of 5%. The assumed health care cost trend rate in 1994 is approximately 11.5%, grading down to an ultimate rate in 2005 of approximately 6%. 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, 1993, by approximately $107 million and the 1993 aggregate service and interest costs by approximately $17 million.

For 1992 and 1991, the cost of postretirement medical and life insurance benefits was based on benefits paid and funded and totaled $98 million and $92 million, respectively.

VOLUNTARY RETIREMENT INCENTIVE PLAN: In 1993, the Company announced a workforce reduction program which included a voluntary retirement incentive plan for certain employees 50 years of age with at least 15 years of service. The additional pension and other postretirement benefits extended in connection with the voluntary retirement incentive plan are reflected in the funded status tables above and are discussed further in Note 8.

POSTEMPLOYMENT BENEFITS: In November 1992, the Financial Accounting Standards Board issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits," which requires employers to adopt accrual accounting for benefits provided to former or inactive employees and their beneficiaries and covered dependents, after employment but before retirement. The Company will adopt the new standard in 1994.

Based on a preliminary valuation by the Company's actuary, it is estimated that the recorded liability for such benefits will increase by approximately $100 million upon adoption. However, due to current regulatory treatment, adoption of SFAS No. 112 is not expected to have a significant impact on the Company's financial position or results of operations.

Note 8 – Workforce Reduction Program

In the first quarter of 1993, the Company announced a corporate reorganization and workforce reduction program which reduced employment positions through a combination of a targeted voluntary retirement incentive plan, targeted voluntary severance, involuntary severance, transitional leaves of absence and attrition.

In March 1993, the CPUC authorized the establishment of a memorandum account to record costs and savings incurred in connection with the workforce reduction program, with the recovery of such costs subject to a reasonableness review by the CPUC. The Company is seeking rate recovery of all costs incurred in connection with the workforce reduction program relating to electric and gas operations.

As of December 31, 1993, the Company has recorded workforce reduction program costs of $264 million, net of a curtailment gain relating to pension benefits. (Included in this amount is $151 million for additional pension benefits and $22 million for other postretirement benefits extended in connection with the voluntary retirement incentive plan.) In April 1993, the Company announced a freeze on electric rates through 1994. As a result, the Company has expensed $190 million of such costs relating to electric operations. The remaining $74 million of such costs relating to gas operations has been deferred for future rate recovery. The amount deferred is currently being amortized as savings are realized.

Note 9 – Income Taxes

The current and deferred components of income tax expense were:

Year ended December 31,	**1993**	1992	1991
(in thousands)			
Current			
Federal	**$ 417,558**	$536,774	$589,713
State	**165,134**	193,895	201,445
Total current	**582,692**	730,669	791,158
Deferred (substantially all federal)			
Regulatory balancing accounts	**77,515**	85,210	(86,682)
Depreciation	**207,690**	165,944	161,937
(Gain) loss on reacquired debt	**42,405**	15,959	(1,377)
Other – net	**11,998**	(78,783)	4,922
Total deferred	**339,608**	188,330	78,800
Investment tax credits – net	**(20,410)**	(23,873)	(18,424)
Total income tax expense	**$ 901,890**	$895,126	$851,534
Classification of income taxes			
Included in operating expenses	**$1,006,774**	$906,845	$863,089
Included in other – net	**(104,884)**	(11,719)	(11,555)
Total income tax expense	**$ 901,890**	$895,126	$851,534

The significant components of net deferred income tax liabilities are as follows:

December 31, 1993	Deferred income tax assets	Deferred income tax liabilities	Net deferred income tax liability
(in thousands)			
Deferred income taxes – current			
Regulatory balancing accounts	$ –	$ 449,216	
Other	160,177	26,545	
Total deferred income taxes – current	160,177	475,761	$ 315,584
Deferred income taxes – noncurrent			
Plant in service	–	3,386,122	
Income tax-related deferred charges[1]	–	511,786	
Other	647,018	728,060	
Total deferred income taxes – noncurrent	647,018	4,625,968	3,978,950
Total deferred income taxes	$807,195	$5,101,729	$4,294,534

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

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

Year ended December 31,	**1993**	1992	1991
Federal statutory income tax rate	**35.0%**	34.0%	34.0%
Increase (decrease) in income tax rate resulting from			
Investment tax credits	**(1.0)**	(1.2)	(1.0)
State income tax (net of federal benefit)	**6.1**	6.1	7.1
Effect of regulatory accounting for depreciation differences	**4.5**	5.0	5.4
Other – net	**1.2**	(0.6)	(0.2)
Effective tax rate	**45.8%**	43.3%	45.3%

Note 10 – Commitments

CAPITAL PROJECTS: Capital expenditures for 1994 are estimated to be approximately $1,729 million, consisting of $1,397 million for utility expenditures, $105 million for Diablo Canyon and $227 million for nonregulated expenditures. At December 31, 1993, Enterprises had firm commitments totaling $241 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 $95 million in 1994, $119 million in 1995,

$27 million in 1996, and none in 1997, 1998, and thereafter. The partnerships which own the generating facility projects typically finance them with nonrecourse debt.

QUALIFYING FACILITIES (QFs): Under the Public Utility Regulatory Policies Act of 1978, the Company is required to purchase electric energy and capacity produced by QFs. The CPUC established a series of power purchase agreements which set the applicable terms, conditions and price options. QFs must meet certain performance obligations, depending on the contract, prior to receiving capacity payments. The total cost of both energy and capacity payments to QFs is recoverable in rates. The Company's contracts with QFs expire on various dates from 1994 to 2022. Under these contracts, the Company 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. There are no requirements to make debt service payments. QF deliveries in the aggregate account for approximately 24% of the Company's 1993 total electric energy requirements and no single contract accounted for more than 5% of the Company's energy needs. QF deliveries in 1993 represented approximately 84% 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,	**1993**	1992	1991
(in millions)			
Kilowatthours received	**21,242**	21,173	19,127
Energy payments	**$ 1,099**	$ 1,084	$ 970
Capacity payments	**$ 503**	$ 489	$ 450

IRRIGATION DISTRICTS AND WATER AGENCIES: The Company 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, the Company must make specified semi-annual minimum payments whether or not any energy is supplied, subject to the provider's retention of FERC 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, 1993, the future minimum payments under these contracts were $34 million for each of the years 1994 through 1998 and a total of $484 million for periods thereafter. Total payments under these contracts were $45 million, $54 million and $47 million in 1993, 1992 and 1991, respectively.

WESTERN AREA POWER ADMINISTRATION (WAPA) ENERGY AGREEMENT: The Company has an agreement with WAPA to purchase energy from them and resell it to them upon their request. The energy under contract has been purchased by the Company from WAPA at favorable prices based on WAPA's cost of generation. That energy must be sold back to WAPA at a price equal to the Company's current thermal production cost at the time of delivery to WAPA less the Company's savings that resulted from the purchases at the lower WAPA prices.

The contract will expire in 2005. At December 31, 1993, the cost to the Company to return the amount of energy currently available to WAPA was approximately $177 million, assuming WAPA requests the return of all the energy prior to the contract's expiration date. However, such cost represents a return of the benefits the Company received through its purchases from WAPA, which were passed on to ratepayers at that time. The Company believes it is entitled to recover in rates costs of energy resold to WAPA.

Note 11 – Contingencies

HELMS PUMPED STORAGE PLANT (HELMS): Helms, a three-unit hydroelectric combined generating and pumped storage facility, completion of which was delayed due to a water conduit rupture in 1982 and various start-up problems related to the plant's generators, became commercially operable in 1984. As a result of the damage caused by the rupture and the delay in the operational date, the Company incurred additional costs which are currently excluded from rate base and lost revenues during the period while the plant was under repair.

The Company has filed an application for rate recovery of the remaining unrecovered Helms costs, the associated revenue requirement on such costs since 1984 and lost revenues during the time the generators were being repaired. The remaining net unrecovered costs of Helms (after adjustment for depreciation) and revenues discussed above totaled $106 million at December 31, 1993.

In June 1993, the DRA issued its report on the Company's 1991 Helms application and recommended a disallowance of all requested costs and revenues. The DRA recommends ratepayers should not be held responsible for plant costs or losses incurred by a utility due to contractor error, whether or not the utility was prudent, and cites past CPUC action for this policy. The DRA also contends the Company acted imprudently in the management of the project and failed to adequately oversee the engineering and design of the generators.

With respect to the lost revenues and related recorded interest during the time that Helms was out of service for the modification and repair of the generators, the DRA asserts the Company has failed to establish that the outage was not caused by a problem first identified during the precommercial testing program.

The Company filed its rebuttal testimony in January 1994 asserting that it was prudent in managing and overseeing the project and various issues raised by DRA were not based on facts or were irrelevant to the application. The Company is uncertain whether, and to what extent, any of the remaining costs and revenues will be recovered through the ratemaking process.

NUCLEAR INSURANCE: The Company is a member of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL I and II). If the nuclear plant of a member utility is damaged or increased costs for business interruption are incurred due to a prolonged accidental outage, the Company may be subject to maximum assessments of $21 million (property damage) or $7 million (business interruption), in each case per policy period, if losses exceed premiums, reserves and other resources of NML, NEIL I or NEIL II.

The federal government has enacted laws that require all utilities with nuclear generating facilities to share in payment for claims resulting from a nuclear incident. The Price-Anderson Act limits industry liability for third-party claims resulting from any nuclear incident to $9 billion per incident. Coverage of the first $200 million is provided by a pool of commercial insurers. If a nuclear incident results in public liability claims in excess of $200 million, the Company 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 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 may be required to take remedial action at certain disposal and retired manufactured gas plant sites if they are determined to present a significant threat to human health or the environment because of an actual or potential release of hazardous substances. The Company has been designated as a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act (federal Superfund law) and the California Hazardous Substance Account Act (California Superfund law) with respect to several sites. The overall costs of the hazardous materials and hazardous waste compliance and remediation activities ultimately undertaken by the Company are difficult to estimate due to uncertainty concerning the Company's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. However, based on the information currently available, the Company has an accrued liability as of December 31, 1993, of $60 million for hazardous waste remediation costs. The ultimate amount of such costs may be significantly higher if, among other things, the Company is held responsible for cleanup at additional sites, other potentially responsible parties are not financially able to contribute to these costs, or further investigation indicates that the extent of contamination and affected natural resources is greater than anticipated at sites for which the Company is responsible.

To the extent that hazardous waste compliance and remediation costs are not recovered through insurance or by other means, the Company will apply for recovery through ratemaking procedures established by the CPUC and expects that most prudently incurred hazardous waste compliance and remediation costs will be recovered through rates. As of December 31, 1993, the Company has a deferred charge of $61 million for most hazardous waste remediation costs, which represents the minimum amount of such costs expected to be recovered. Due to expected regulatory treatment, the Company believes that the ultimate outcome of these matters will not have a significant adverse impact on its financial position or results of operations.

LEGAL MATTERS: Antitrust Litigation: In December 1993, the County of Stanislaus, California, and a residential customer of PG&E, filed a complaint against PG&E and PGT on behalf of themselves and purportedly as a class action on behalf of all natural gas customers of PG&E, for the period of February 1988 through October 1993. The complaint alleges that the purchase of natural gas in Canada by A&S was accomplished in violation of various antitrust laws which resulted in increased prices of natural gas for PG&E's customers.

The complaint alleges that the Company could have purchased as much as 50% of its Canadian gas on the spot market instead of relying on long-term contracts and that the damage to the class members is at least as much as the price differential multiplied by the replacement volume of gas, an amount estimated in the complaint as potentially exceeding $800 million. The complaint indicates that the damages to the class could include over $150 million paid by the Company to terminate the contracts with the Canadian gas producers in November 1993. The complaint also seeks recovery of three times the amount of the actual damages pursuant to antitrust laws.

The Company believes the case is without merit and has filed a motion to dismiss the complaint. The Company believes that the ultimate outcome of the antitrust litigation will not have a significant adverse impact on its financial position.

Hinkley Litigation: In 1993, a complaint was filed in San Bernadino County Superior Court on behalf of a number 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 the Company's Hinkley Compressor Station, as well as punitive damages.

The plaintiffs contend that the Company discharged chromium-contaminated waste water into unlined ponds, which led to chromium percolating into the groundwater of surrounding property. The plaintiffs further allege that the Company disposed of the chromium in those ponds to avoid costly alternatives.

In 1987, the Company undertook an extensive project to remediate potential groundwater chromium contamination. The Company has incurred substantially all of the costs it currently deems necessary to clean up the affected groundwater contamination. In accordance with the remediation plan approved by the regional water quality control board, the Company will continue to monitor the affected area and periodically perform environmental assessments.

In November 1993, the parties engaged in private mediation sessions. In December 1993, the plaintiffs filed an offer to compromise and settle their claims against the Company for $250 million.

The Company is unable to estimate the ultimate outcome of this matter, but such outcome could have a significant adverse impact on the Company's results of operations. The Company believes that the ultimate outcome of this matter will not have a significant adverse impact on its financial position.

QF Transmission Litigation: The Company is a defendant in a lawsuit, currently in trial, resulting from the termination of a power purchase agreement. The plaintiff contends the Company misrepresented to the CPUC and to QFs its transmission capacity and that the existence of transmission constraints extended the deadline for delivery of energy. The plaintiff also alleges the Company had an obligation to build transmission upgrades at the Company's expense, which it did not fulfill. The complaint seeks compensatory and punitive damages of an unspecified amount. However, the plaintiff's damage expert has given a preliminary estimate of damages sought of $67 million. There are other similarly situated QFs which might choose to file similar complaints depending on the outcome of this litigation. The Company believes that the matter has no merit and that the ultimate outcome will not have a significant adverse impact on its financial position or results of operations.

Quarterly Financial Data

The four quarters of 1993 and 1992 are shown below. 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 by quarter during the year.

In the second quarter of 1993, the Company charged to earnings $141 million related to the workforce reduction program for management employees. In the third quarter of 1993, the Company's earnings reflected charges of $144 million resulting from the Company's workforce reduction program, termination of Canadian gas contracts and an increase in the federal income tax rate that was signed into law this year. The fourth quarter of 1993 reflected charges against earnings of $126 million for Canadian gas costs incurred by the Company for 1988 through 1990 and for commitments for gas transportation capacity. Earnings for the second quarter of 1992 included a $19 million after-tax gain from the sale by PGT of its 49.98% interest in ANG.

The Company's common stock is traded on the New York, Pacific, London, Amsterdam, Basel and Zürich stock exchanges. There were approximately 245,000 common shareholders of record at December 31, 1993. Dividends are paid on a quarterly basis, and there are no significant restrictions on the present ability of the Company to pay dividends.

Quarter ended	December 31	September 30	June 30	March 31
(in thousands, except per share amounts)				
1993				
Operating revenues	**$ 2,707,171**	**$ 2,947,294**	**$ 2,464,125**	**$ 2,463,818**
Operating income	**428,914**	**525,981**	**387,707**	**420,328**
Net income	**208,382**	**356,099**	**245,350**	**255,664**
Earnings per common share[1]	**.45**	**.79**	**.53**	**.56**
Dividends declared per common share	**.47**	**.47**	**.47**	**.47**
Common stock price per share				
High	**36.75**	**36.63**	**35.38**	**35.75**
Low	**33.50**	**33.13**	**31.75**	**31.75**
1992				
Operating revenues	$2,557,787	$2,798,763	$2,519,679	$2,419,859
Operating income	386,196	507,137	491,131	448,977
Net income	205,804	351,939	336,409	276,429
Earnings per common share[1]	.44	.78	.75	.61
Dividends declared per common share	.44	.44	.44	.44
Common stock price per share				
High	34.00	34.63	33.63	32.38
Low	30.00	31.13	29.00	29.13

[1] *Includes Diablo Canyon scheduled refueling outages for the first and second quarters of 1993 and for the third and fourth quarters of 1992.*

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, 1993 and 1992, and the related statements of consolidated income, cash flows, common stock equity and preferred stock, and the schedule of consolidated segment information for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the 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, 1993 and 1992, and the results of their operations and cash flows for each of the three years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 2 of Notes to Consolidated Financial Statements, the reasonableness of Canadian gas costs for 1988 through 1993 is subject to California Public Utilities Commission review. The Company currently is unable to estimate the ultimate outcome of the gas reasonableness proceedings or predict whether such outcome will have a significant adverse impact on its financial position or results of operations.

As discussed in Note 11 of Notes to Consolidated Financial Statements, the Company has filed an application for rate recovery of the remaining unrecovered Helms costs and certain lost revenues which totaled $106 million at December 31, 1993. The Company is uncertain whether, and to what extent, any of the remaining costs and revenues will be recovered through the ratemaking process.

As discussed in Note 11 of Notes to Consolidated Financial Statements, in 1993, a complaint was filed on behalf of a number of individuals seeking recovery for personal injuries and property damage related to alleged groundwater contamination caused by Company activity. The Company is unable to estimate the ultimate outcome of this matter, but such outcome could have a significant adverse impact on the Company's results of operations. The Company believes that the ultimate outcome of this matter will not have a significant adverse impact on the Company's financial position.

As explained in Notes 1 and 7 of Notes to Consolidated Financial Statements, effective January 1, 1993, the Company changed its method of accounting for postretirement benefits other than pensions and for income taxes.

ARTHUR ANDERSEN & CO.
San Francisco, California
February 16, 1994

The responsibility for the integrity of the financial information included in this report rests with management. Such information has been prepared in accordance with generally accepted accounting principles appropriate in the circumstances, and is 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 financial information. 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 & Co., 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.

In a further attempt to assure objectivity and remove bias, 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 & Co., 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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Former Chairman of the Board and Chief Executive Officer, Crocker National Corporation and Crocker National Bank

Samuel T. Reeves
President and Co-Chairman of the Board, Dunavant Enterprises, Inc. (cotton merchandising)

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

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

Alan Seelenfreund*
Chairman of the Board and Chief Executive Officer, McKesson Corporation (distributor of pharmaceuticals and health care products)

Stanley T. Skinner
President and Chief Operating Officer, Pacific Gas and Electric Company

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

† *As of February 1, 1994*
* *Elected October 1, 1993*

PERMANENT COMMITTEES OF THE BOARD OF DIRECTORS

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

Richard A. Clarke (Chairman)
Harry M. Conger
Leslie L. Luttgens
Richard B. Madden
John B. M. Place
Stanley T. Skinner

Audit Committee
Reviews financial statements and internal accounting and control procedures with independent public accountants.

Harry M. Conger (Chairman)
William S. Davila
Melvin B. Lane
Mary S. Metz
Alan Seelenfreund
Barry Lawson Williams

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

Richard A. Clarke (Chairman)
Richard B. Madden
William F. Miller
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.

Leslie L. Luttgens (Chairman)
William F. Miller
John B. M. Place
Samuel T. Reeves
John C. Sawhill

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

Richard A. Clarke (Chairman)
William S. Davila
Melvin B. Lane
Mary S. Metz
John C. Sawhill

PG&E OFFICERS†

* **Richard A. Clarke**
Chairman of the Board and
Chief Executive Officer

* **Stanley T. Skinner**
President and
Chief Operating Officer

* **Jerry R. McLeod**
Executive Vice President

* **James D. Shiffer**
Executive Vice President

* **Robert D. Glynn, Jr.**
Senior Vice President
and General Manager,
Customer Energy Services
Business Unit

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

* **Virgil G. Rose**
Senior Vice President
and General Manager,
Electric Supply Business Unit

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

Norman L. Bryan
Vice President
Marketing

John C. Danielsen
Vice President
Computer and
Telecommunications Services

† *As of February 1, 1994*
* *Member Management Committee*

Richard A. Draeger
Vice President
General Services

Roger J. Flynn
Vice President
San Joaquin Region

Warren H. Fujimoto
Vice President
Nuclear Technical Services

Howard V. Golub
Vice President and
General Counsel

Leland M. Gustafson
Vice President
Bay Region

Robert J. Haywood
Vice President
Power System

Thomas W. High
Vice President and
Assistant to the Chairman of
the Board

Grant N. Horne
Vice President
Corporate Communications

Lendrith L. Jackson
Vice President
Customer Services

John C. Keyser
Vice President
Northern Region

John E. Koehn
Vice President
Community and
Governmental Relations

William R. Mazotti
Vice President
Gas Services and Operations

Peter C. Nelson
Vice President
Mission Trail Region

Jackalyne Pfannenstiel
Vice President
Corporate Planning

James H. Pope
Vice President
Technical and Construction
Services

James K. Randolph
Vice President
Power Generation

Gordon R. Smith
Vice President and
Chief Financial Officer

John D. Townsend
Vice President
Diablo Canyon Operations
and Plant Manager

Barbara Coull Williams
Vice President
Human Resources

Leslie H. Everett
Corporate Secretary

Kent M. Harvey
Treasurer

Thomas C. Long
Controller

Brian L. McGrath
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Julia B. York
Assistant Treasurer

CHIEF EXECUTIVE OFFICERS OF PRINCIPAL PG&E SUBSIDIARIES

Mason Willrich
President and Chief
Executive Officer
PG&E Enterprises

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

Donald McMorland
Chairman of the Board
Alberta and Southern
Gas Co. Ltd.

CHIEF EXECUTIVE OFFICERS OF PRINCIPAL PG&E ENTERPRISES SUBSIDIARIES AND RELATED VENTURES

Joseph T. Williams
President and Chief
Executive Officer
PG&E Resources Company

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

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

Mason Willrich
Chairman of the Board and
Chief Executive Officer
PG&E Properties, Inc.

SHAREHOLDER SERVICES OFFICE
77 BEALE STREET, ROOM 2600
SAN FRANCISCO, CA
1-800-367-7731

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

MANAGER OF SHAREHOLDER SERVICES
Leslie Guliasi
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 to the Office of the Corporate Secretary at the following address:

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 to the Director of Investor Relations at the following address:

DIRECTOR OF INVESTOR RELATIONS
Laura L. Mountcastle
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 customers.

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 enrollment form by contacting the Shareholder Services Office. If your certificates are held by a broker (in "street name"), you are not eligible to participate in the 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 in writing immediately.

ANNUAL MEETING OF SHAREHOLDERS

Date: April 20, 1994
Time: 10:00 a.m.
Location: Masonic Auditorium
1111 California Street
San Francisco, California

A notice of the meeting, proxy statement, and proxy form are being mailed with this annual report on or about March 3, 1994, to all shareholders of record.

1994 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 Company's common stock is usually listed in the newspaper under "PacGE."

The Company has 15 issues of preferred stock, most 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:	
8.20%	PGEpfP
8.00%	PGEpfO
7.84%	PGEpfM
7.44 %	PGEpfQ
7.04%	PGEpfU
6.875%	PGEpfX
6.57%	Unlisted
5.00%	PGEpfD
5.00% Series A	PGEpfE
4.80%	PGEpfG
4.50%	PGEpfH
4.36%	PGEpfI
Non-Redeemable:	
6.00%	PGEpfA
5.50%	PGEpfB
5.00%	PGEpfC

10-K REPORT

If you would like a copy of the Company's 1993 Form 10-K Report to the Securities and Exchange Commission, please contact the Shareholder Services Office.

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