Pacific Gas and Electric Company

Lawrence F. Womack
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March 31, 1999

PG&E Letter DCL-99-045
HBL-99-005

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Docket No. 50-133, OP-DPR-7
Humboldt Bay Unit 3
<u>1998 Annual Report</u>

Dear Commissioners and Staff:

Pursuant to 10 CFR 50.71(b) and 10 CFR 140.15(b)(1), enclosed are 15 copies of PG&E's Annual Report and financial information for the calendar year 1998.

Sincerely,

Larry F. Womack

cc: Steven D. Bloom
Ira P. Dinitz
Ellis W. Merschoff
David L. Proulx
Louis L. Wheeler

Enclosures

WEC/2013

M004

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1998

PG&E Corporation

Annual Report

Financial Highlights

(dollars in millions, except per share amounts)	1998	1997	% Change
For the Year			
Operating revenues	$ 19,942	$ 15,400	29.5
Operating income	$ 2,007	$ 1,728	16.1
Net income	$ 719	$ 716	0.4
Earnings per share, basic and diluted	$ 1.88	$ 1.75	7.4
Dividends declared per common share	$ 1.20	$ 1.20	—
At Year-End			
Total assets	$ 33,234	$ 31,115	6.8
Number of common shareholders	164,000	180,000	(8.9)
Number of common shares outstanding	382,603,564	417,665,891	(8.4)

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PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. The Corporation's businesses provide energy services throughout North America. PG&E Corporation's Northern and Central California energy utility subsidiary, **Pacific Gas and Electric Company**, provides natural gas and electric service to one of every 20 Americans. PG&E Corporation's four unregulated businesses provide a wide range of energy products and services: **U.S. Generating Company** develops, builds, operates, owns, and manages power generation facilities that serve wholesale and industrial customers; **PG&E Gas Transmission** operates approximately 9,000 miles of natural gas pipelines, natural gas storage facilities, and natural gas processing plants in the Pacific Northwest and Texas; **PG&E Energy Trading** purchases and resells energy commodities and related financial instruments in major North American markets, serving PG&E Corporation's other unregulated businesses, unaffiliated utilities, and large end-use customers; and **PG&E Energy Services** provides retail competitively priced electricity, natural gas, and related services to lower overall energy costs for industrial, commercial, and institutional customers.

Performance Delivered.

Commitment to Growth.

PG&E Corporation's objective is to be the premier energy services company as measured by shareholders, customers, and employees.

letter to shareholders

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

1998 was a breakthrough year for your Company, and here are a few highlights.

- Earnings per share grew 7.4 percent to $1.88.
- Earnings per share from operations grew approximately 12 percent to $1.94.
- From these results, we returned more than $1.6 billion to our shareholders, including $470 million in dividends and $1.2 billion in share repurchases.

Our utility business improved its operating efficiency, making significant progress toward its goal of earning the return authorized by the California Public Utilities Commission on its energy delivery business.

Our unregulated businesses had a solidly profitable year, delivering $0.12 per share from operations, compared with a loss last year.

Our team grew in the strength and depth of the talent we have deployed in the competitive marketplace.

We accomplished these results by focusing on our objective of being the premier energy services company, as measured by shareholders, customers, and employees.

The National Energy Marketplace

In 1998, electric energy markets opened in a number of states, following the trend of opening wholesale markets for electricity and both wholesale and retail markets for natural gas. Electric customers in California, Massachusetts, and Rhode Island, which make up about 13 percent of the total U.S. electric customer base, now have their choice of electric commodity providers.

We accomplished these results by focusing on our objective of being the premier energy services company, as measured by shareholders, customers, and employees.

Voters in California and Massachusetts, states which represent about 14 percent of the U.S. population, resoundingly confirmed their support for electric deregulation by three-to-one margins on two ballot propositions that threatened to roll back competition. We feel that with these votes, customers said, in effect, that they don't expect unattainable perfection in deregulation plans, just common sense and speedy progress.

Utility Business

Pacific Gas and Electric Company, our utility business, made real progress in 1998. We implemented the systems and procedures necessary to permit electric customers to choose, for the first time ever, their electricity commodity provider. We've been championing customer choice for years, and by year-end, about 50,000 customers, whose annual electric use represents more than 10 percent of the company's delivered electricity, elected to switch to alternate electric commodity providers.

We announced or completed utility power plant divestiture transactions totaling $1.5 billion in value.

Our Diablo Canyon Power Plant retained the top position in its industry, the only nuclear power plant to have continually received a No. 1 rating, the highest granted by the Institute of Nuclear Power Operations. And Diablo Canyon's Unit 1 set a world record in 1998 among comparable units for continuous net generation.

The investments we made in systems and infrastructure paid off during severe storms in the winter of early 1998.

The investments we made in systems and infrastructure paid off during severe storms in the winter of early 1998, with fewer customer outages, shorter outages when they did occur, and better information easily and quickly shared with customers who needed it.

Unregulated Businesses

Our unregulated businesses also had an excellent year.

In our business lines that operate in wholesale energy markets, we completed the acquisition of New England Electric System's conventional power plants. This added about 600 new team members and approximately 4,800 megawatts of generating plants and purchased-power capacity, and more than doubled the size of U.S. Generating Company, making it one of New England's largest competitive electric suppliers. Among this year's achievements, our power plant in Pittsfield, Massachusetts continued for a sixth year its operation without a lost-time accident, and our Northampton and Scrub Grass plants in Pennsylvania were both recipients of the 1998 Governor's Award for Environmental Excellence.

We are choosing to focus our resources – that is, our people and your investment – squarely on rapidly growing opportunities in the North American energy markets.

Our Texas gas operations beat their previous operating reliability record for natural gas liquids products, reaching 99.69 percent. In the Northwest, our pipeline surpassed its prior annual throughput record, delivering almost 915 billion cubic feet of natural gas. And our energy trading unit had revenue growth of 75 percent in power trading and natural gas operations.

Our retail energy services business, in its second year of start-up, reached more than $2 billion in contract awards for large-scale energy projects and commodities, as markets opened across the United States and as customers seek to lower their expenditures for energy.

We completed the divestiture of our Australian pipeline business in 1998, choosing to focus our human and financial resources – that is, our people and your investment – squarely on rapidly growing opportunities in the North American energy markets.

1998

In 1998, we focused on being the premier energy services company as measured by shareholders, customers, and employees.

For shareholders, we focused on growing earnings per share and growing the proportion of earnings from unregulated businesses.

For customers, we focused on providing energy commodities and services – safely, reliably, and at fair prices.

For employees, we strive to provide a safe work environment, the tools and training to do the job well, and a clear understanding of how to measure the operational and financial success of their work. And we motivate all of our leaders to constantly improve their teams and to surround themselves with members of the "A Team," those men and women with high personal standards, low tolerance for mediocrity, impatience with the status quo, and the zeal, commitment, and skills to deliver better every day.

We aim to deliver sustained, superior financial growth so our shareholders will be pleased they have invested in "PCG."

In 1998, we grew the responsibility of many existing team members, and we added a number of strong, experienced team members in key leadership positions. And in doing so, we raised the leadership performance bar for us all.

That was a lot of the good news about 1998.

But, we're not satisfied with our financial performance. Our Texas natural gas operating business is underperforming and the start-up costs of our energy services unit exceeded budget. And all of our businesses have room to improve. We are focused on making all of our businesses top performers in the future.

1999 and Beyond

It's already 1999, and we want to share some of the things that are down the road.

We see great opportunities in the North American energy marketplace to provide strong, sustained growth in each of our businesses. These opportunities are driven by changes in the energy industry, from the opening to competition of markets previously closed or constrained, and from the demonstrated desire of customers to lower their energy costs through choice and competition. We conduct business in many locations in North America, and we have substantial business presence in the Northeast, Texas, California, and the Northwest. There are opportunities to continue to grow value in those locations as well as to move into other attractive regions, leveraging the assets and skills already in place.

To achieve success for you from these opportunities, we will continue to raise the bar for ourselves to deliver to each of our constituencies. We aim to deliver sustained, superior financial growth so our shareholders will be pleased they have invested in "PCG," to deliver energy commodities and services that thrill customers with their value, and to provide a work environment that will bring out the competitive best in every employee.

Thank you for being our shareholders, our customers, our employees – in some cases, all three. We feel good about 1998. We're working to make 1999 – and beyond – even better.

Robert D. Glynn, Jr.

ROBERT D. GLYNN, JR.
Chairman of the Board, Chief Executive Officer, and President
February 8, 1999

For utility customers, premier means safe, reliable, responsive service.

It means easy access to information about their service.

It means choice.

It means low costs.

Premier means excellence.

It means honesty, ethics, performance.

What does it mean to be the premier energy services company?

For customers on the unregulated side of our business, it also means demonstrated experience along the entire energy value chain.

Across multiple commodities.

Across all the locations where customers operate.

It means competitive prices.

utility business

Pacific Gas and Electric Company

At A Glance

PG&E Corporation's regulated utility, Pacific Gas and Electric Company, is one of the largest investor-owned gas and electric utilities in the United States.

Operating revenue	1998 $8.9 billion	1997 $9.5 billion
Earnings per common share	$1.82	$1.79
Service area	70,000 square miles of territory in Northern and Central California, with a population of 13 million, about one in 20 Americans	
Delivery systems	131,000 circuit miles of electric transmission and distribution lines 43,000 miles of natural gas transmission and distribution pipelines	
Recent investments in infrastructure	$1.4 billion in 1998, $[illegible].8 billion in 1996 and 1997	
Sources of power	California Power Exchange*	
Value of generating assets sold in 1998	$1.5 billion in sales of fossil-fueled and geothermal generating assets; $501 million in sales completed in 1998; more than $1 billion expected to close in 1999	
A few of the businesses served by Pacific Gas and Electric Company	970 wineries, 38 gold mines, 2,6[illegible]2 bakeries, 1,048 shoe stores, 1,809 video rental stores, 588 golf courses, 1,217 florists, and 1,009 car washes	
Estimated energy savings through energy efficiency programs	340 million kilowatt-hours of electricity, or the equivalent to supply 51,000 households 8.3 million therms of natural gas, or the equivalent to supply 15,000 homes	

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

We Deliver Energy

Step into a new construction site in Silicon Valley, a winter storm in the Sierra, or a customer Call Center in Fresno, and you will see Pacific Gas and Electric Company in action – installing electric lines for the next technology powerhouse, restoring service to a hillside town, and talking with a customer, scheduling a time when she can expect a visit from one of our service specialists.

Our utility, Pacific Gas and Electric Company, continued to do all of this and much more in 1998, in order to deliver electricity, natural gas, and customer service to the 13 million people and thousands of businesses we serve in Northern and Central California, one of the most robust economies in the world.

From a growth rate of only 1 to 2 percent in the 1980s and early 1990s, demand for electricity has doubled in parts of our service territory during the last three years. We serve some "boomtowns" with average growth rates as high as 9 percent, and there is more growth coming.

Investing In Service and Reliability

The focus of our utility business today is best captured in its "tag line" – *We Deliver Energy* – seen by millions of customers every day on its trucks, advertising, correspondence, and web page. Customers also see how we live out this commitment every day through the services our utility provides. Substantial infrastructure investments significantly reduced service interruptions in 1998. Even through the El Niño winter of 1997-1998, Pacific Gas and Electric Company reduced the average time a customer was without power during storms by 46 percent compared to the previous year's storms. Because of improved service, faster restorations, and better communications, 90 percent of our utility customers now rate our utility service as good, very good, or excellent.

Delivering Energy and Choice

We delivered energy in 1998, but we also delivered something more. We delivered choice.

We are investing in utility infrastructure to power the future.

Pacific Gas and Electric Company delivers electricity at the speed of light through overhead lines that require continual maintenance and repair, as demonstrated here by linemen Bill Goodman, left, and Joe Little. The utility's electric distribution infrastructure includes more than 91,000 circuit miles of overhead electric lines, 2.2 million utility poles, 777,000 transformers, and 778 substations, all designed and maintained to ensure reliable energy delivery from any electric supplier. In 1998, the utility's distribution capacity was increased by 1,100 megawatts, enough to serve more than one million homes.

PACIFIC GAS AND ELECTRIC COMPANY

San Francisco, California

Beginning in March 1998, Californians were given the ability to choose their own electricity provider. While the electricity they buy is still delivered by the utility, the electricity itself may come from any one of more than 60 electricity providers. Building the technical infrastructure and billing systems required to support choice was an unprecedented task.

PG&E Corporation has long been a strong advocate for choice. A few years ago, we were joined by a broad coalition of business and community leaders in California to support landmark legislation that created the framework for deregulating the state's electric utility industry. California Assembly Bill 1890 (AB 1890) passed in 1996, and it marked the beginning of a new era.

AB 1890 made sure that smaller customers were at the front of the line to receive benefits from deregulation. Right from the start, in January 1998, residential and small business customers received an across-the-board 10 percent electric rate decrease, which saved them about $400 million in 1998 alone.

Industrial customers also benefited from the regulatory restructuring that occurred in California. In fact, they were the key drivers of the move to a more open energy marketplace nationwide, having recognized early that direct access to competitive energy suppliers creates tremendous opportunities for them to reduce their energy costs.

Shifting Assets

Deregulation created clear incentives for moving the ownership of power plants away from utility companies. As a result, we moved forward with selling our utility

We deliver energy, along with personal and responsive service.

With recent enhancements, Pacific Gas and Electric Company's Call Centers have the capacity to handle more than 500,000 calls per hour. More than 1,000 Call Center representatives, including Gina Pongasi, left, efficiently handle all types of customer inquiries, while a sophisticated automated response system provides specific information about temporary outages and restoration times. Serving the diverse markets of Northern and Central California, the utility can provide customer information in as many as 140 languages, including Spanish, Chinese, Vietnamese, Russian, Korean, Japanese, and Hmong.

PACIFIC GAS AND ELECTRIC COMPANY

Sacramento, California

power generating assets in 1998. We closed the sale of three fossil-fueled power plants for $501 million in the third quarter of the year, and we contracted to sell four additional electric generating power plants during the fourth quarter for an additional $1 billion. These massive asset sales allow the utility to focus on the future of its business – transmission and delivery – and to recover its investment in these generating assets. Proceeds from these sales will be used to offset costs associated with other generating assets and the transition to a competitive market framework.

Some generating facilities are expected to remain within the utility, including the Diablo Canyon Nuclear Power Plant, which satisfies the equivalent of 20 percent of utility customer demand.

Generating Earnings, Building For the Future

To be successful, Pacific Gas and Electric Company needs to deliver adequate financial returns as well as reliable utility services. Its goal is to consistently earn its full authorized rate of return, which is set by the California Public Utilities Commission.

The utility's future has a strong foundation to build upon – a rich and growing service area, a culture of reliability, and a bond with its communities. In 1998, the company weathered tremendous storms and historic change. But through it all the utility continues to improve doing what matters most: delivering low-cost gas and electric service that is safe, reliable, and responsive to customer needs. We will deliver all of that, and much more, in our future.

unregulated businesses

Unregulated Businesses At A Glance

Through its unregulated businesses, PG&E Corporation provides a full range of energy products and services to a growing base of industrial, commercial, and institutional customers in the United States and Canada.

Operating revenue	1998 $11.7 billion	1997 $6.4 billion
Earnings per common share	$0.06*	($0.04)
Products and services Wholesale	Power generation Development of new power generation facilities Electricity and natural gas commodity supply Natural gas processing, storage, and transporting Energy commodity trading and price risk management services	
Retail	Electricity and natural gas for industrial, commercial, and institutional customers nationwide Energy billing and information management Energy efficiency and power quality solutions Clean Choice™, renewable electric service for customers in California Capital for energy solutions	
Operating power plants	30, representing more than 6,500 megawatts of capacity	
Power plants in development	11, representing more than 8,000 megawatts	
Energy trading volume in 1998 Gas	9.37 billion cubic feet per day	
Power	83 million megawatt-hours	
Gas pipelines	9,000 miles for natural gas, 500 miles for natural gas liquids	
Average daily natural gas throughput	6 billion cubic feet	
Average daily natural gas liquids production	94,500 barrels	
Total value of energy services managed under retail contracts that extend through the year 2003	More than $2 billion	

* Earnings per common share were $0.12 from operations before a $0.06 charge related to the sale of PG&E Corporation's Australian gas assets.

The National Energy Marketplace – A World of Profitable Opportunities

Step into a General Electric Plastics facility in New York, a power generating facility in Massachusetts, a McDonald's restaurant in Los Angeles, a Chevron gas station in Texas, and you will see PG&E Corporation's national energy strategy in action.

In 27 states and in Canada – in power plants and high technology firms, manufacturing facilities and diverse utility operations – PG&E Corporation's unregulated businesses are bringing power, heat, and light to millions of new customers, and delivering growing returns to shareholders along the way.

PG&E Corporation's unregulated businesses provide wholesale and retail energy products and services across North America, bringing together the expertise and energy resources needed to help each customer take advantage of today's expansive energy marketplace. Through our subsidiaries, we generate power in 10 states for sale to wholesale and industrial customers; we process, transport, and store natural gas and natural gas liquids in Texas and the Northwest; we provide trading and price risk management services to wholesale customers nationwide; and we provide innovative, custom-tailored energy management solutions to retail customers in a broad range of industries and localities, along with the capital for these energy solutions.

Our unregulated businesses do it all, nationwide, helping to make PG&E Corporation the premier energy services company in North America.

Premier Power Generation

In 1998, PG&E Corporation completed the $1.59 billion acquisition of 18 hydroelectric and fossil-fueled generating plants from New England Electric System. The sale was one of the largest utility asset acquisitions in U.S. history, transferring three fossil-fueled generating plants, 15 hydroelectric stations, and 23 multi-year power purchase agreements, which in total added approximately 4,800 megawatts of capacity to PG&E Corporation's power generating subsidiary, U.S. Generating Company (USGen), With contracts for as much as 400,000 pounds of steam per hour supplied by Selkirk Generating Plant, managed by U.S. Generating Company, GE Plastics produces high-performance engineering thermoplastics for use in automobiles, aircraft, appliances, packaging, and construction in its world-class Selkirk facility, pictured here. Anthony Ligato, general manager of the Selkirk Generating Plant, right, and GE Plastics general manager Tom Heeps know the advantages of innovative energy partnerships. The 345-megawatt natural gas-fueled Selkirk facility is located on the grounds of GE Plastics' complex and also provides up to 265 megawatts of electricity to Consolidated Edison Company and sells more than 80 megawatts to wholesale power purchasers such as Niagara Mohawk Power Corporation. This is enough power to meet the needs of about 345,000 homes.

Selkirk, New York

We develop and operate reliable, efficient power generating facilities for wholesale energy customers nationwide.

enough to power about 5 million homes in the Northeast. This acquisition increased the power generating capabilities of our unregulated businesses to more than 7,700 megawatts, giving them one of the industry's most impressive portfolios of efficient, reliable generating assets and purchased-power capacity.

In addition to producing power every day for millions of Americans nationwide, USGen has set itself apart in the marketplace as a developer of new power projects. The company is developing a number of highly efficient natural gas merchant power plants in California, the Midwest, Texas, and the Northeast, representing more than 8,000 megawatts of new generating capability. These facilities will be in the new wave of competitively priced electric generating plants built specifically to serve the new, open marketplace. The new facilities, which will be completed during the next four years, will substantially expand USGen's power generating portfolio and allow the company to supply an expanding base of wholesale customers with efficient, reliable, and competitively priced electricity.

Reliable Gas Transmission

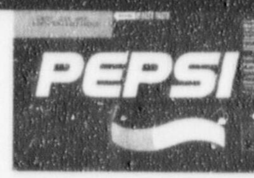
PG&E Gas Transmission owns and operates natural gas pipelines and produces natural gas liquids in Texas and the Pacific Northwest, serving some of the fastest growing

With 62 manufacturing and distribution centers throughout the Midwest, Pepsi-Cola General Bottlers, Inc., looked to PG&E Energy Services to provide premier energy services that would increase efficiencies and reduce energy costs. "A large portion of our operating budget must go to energy-related expenses," says Gary Kowaleski, energy manager for Pepsi-Cola General Bottlers, Inc., left, shown talking with Dean Nicol, PG&E Energy Services integrated services director, at the Chicago Distribution Center. "PG&E Energy Services offered us a customized energy portfolio for natural gas, and just as important, is managing all our energy bills through advanced information systems and energy management services."

Our tailor-made partnerships with retail customers help them reduce their energy costs and improve the bottom line.

Chicago, Illinois

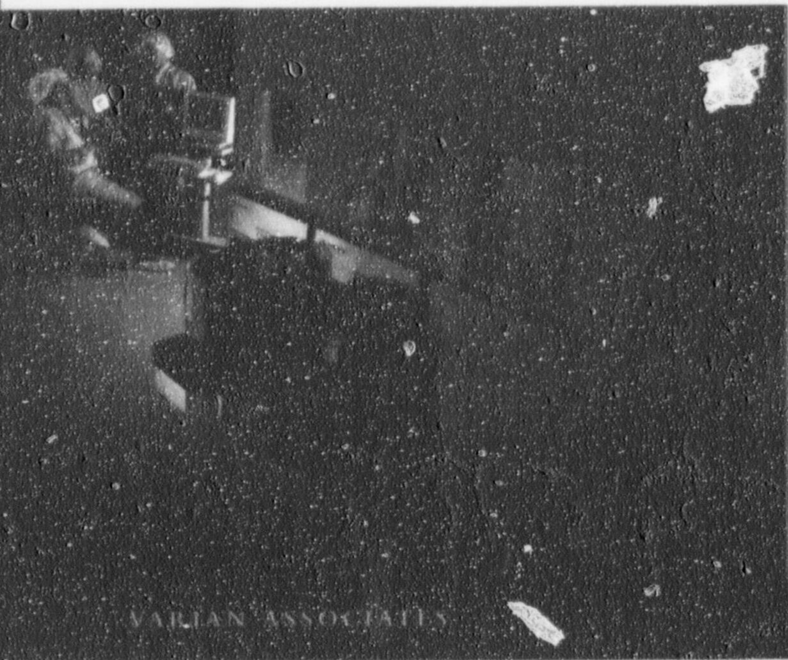
PEPSI-COLA GENERAL BOTTLERS, INC.



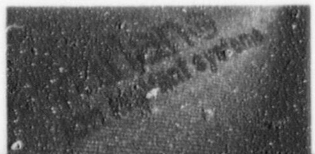
markets in the United States. Taken together with interests the company holds in natural gas pipelines in the Northeast, these impressive facilities make PG&E Gas Transmission a leading natural gas company in the United States today. In 1998, our gas processing plants in Texas and our Northwest system had average reliability rates of 99.69 percent and 99.19 percent, respectively.

In Texas, natural gas markets remained very competitive throughout 1998. However, our 8,000-mile pipeline system, 500 miles of natural gas liquids pipeline, and nine natural gas processing plants are strategic assets that give us a valuable presence in Texas and are a critical part of the national pipeline grid that reaches markets coast to coast. The capability to physically deliver natural gas anywhere in North America is an important part of our national energy strategy.

Our Northwest pipeline transported nearly 915 billion cubic feet of natural gas in 1998. PG&E Gas Transmission is the largest U.S. transporter of Canadian natural gas through this 612-mile, open-access pipeline, which extends from British Columbia through Idaho, Washington, and Oregon to the California border. California is the primary market for our Northwest pipeline, and it is a state that continues to outperform the United States as a whole in terms of growth and power demands.



Varian Associates is one of many high technology companies in Massachusetts that recognize the value of procuring energy services through PG&E Energy Services. "We've reduced our energy costs significantly," says Dick Josephson, seated left, Varian's plant facilities and services manager, shown here at Varian's semiconductor fabrication equipment manufacturing plant in Gloucester with manufacturing engineering technology manager, Laleh Nabipour, and PG&E Energy Services' Malcolm Ticknor, integrated services manager. Through an alliance with the Massachusetts High Technology Council, PG&E Energy Services is bringing power and other energy services to dozens of the Council's corporate members.



Gloucester, Massachusetts

Our energy alliances leverage resources from all our unregulated businesses to create long-term value for customers.

Gas transmission assets PG&E Corporation owned in Australia were sold in 1998, as part of our efforts to refocus our business on the national energy marketplace.

Wholesale Trading

PG&E Corporation's trading operation, PG&E Energy Trading, brings our power and natural gas capabilities together and packages them for wholesale customers. With headquarters in Houston and energy trading floors there and in Bethesda and Calgary, this fast-paced, high-volume commodity enterprise traded more natural gas and power than almost any of its competitors in 1998, creating the North American presence required to support our national energy strategy.

Energy trading is a cornerstone of our integrated service approach. PG&E Energy Trading creates operational flexibility for wholesale suppliers, distributors, and our unregulated affiliates through innovative energy trading products that are based on historical consumption patterns and mathematical forecasts. These new products give consumers and suppliers choices never available from energy providers in the past.

Overall, PG&E Energy Trading's capability allows us to offer customers what is almost as important as energy itself – source reliability, flexibility, and pricing tailored to energy usage in one of the most volatile markets in the world.

NW Natural and its predecessors have been fueling the growth of greater Portland for nearly 140 years. This liquefied natural gas facility makes it possible for NW Natural to purchase gas and transport it on PG&E Gas Transmission's pipeline during the summer months, when consumer usage and gas market prices are lower, and store it in a compact, liquefied state for use during the winter, when consumer demand and gas market prices are higher. Randy Friedman, NW Natural's manager of gas supply, shown left, depends on Dave Sloan, PG&E Gas Transmission's manager of distribution markets, for expert, individualized customer service.

We offer customers management expertise across a wide spectrum of energy commodities and services.

Portland, Oregon

A Year of Expanded Retail Services

PG&E Corporation's unregulated businesses extended their reach in the retail marketplace in 1998, meeting customer needs for energy commodities and energy services management nationwide. Our list of retail customers includes some of the top names in business today. In 1998 alone, our retail subsidiary, PG&E Energy Services, signed new agreements for energy services with IBM, Pepsi-Cola General Bottlers, Safeway, The Massachusetts High Technology Council, and many more.

With offices in 20 major cities in the United States, PG&E Energy Services is well positioned to meet the needs of these valuable retail customers. We enhance our customers' bottom line by lowering consumption through energy-efficiency measures, by delivering competitive commodity prices, and by reducing the risk of costly production losses due to power disruptions.

With a strong asset base and expertise across a wide spectrum of energy supply and consumption, PG&E Corporation's unregulated businesses leverage their resources to build custom-tailored energy services to meet the needs of all our customers.

The Massachusetts High Technology Council, which represents about 200 high technology companies statewide, recently entered an alliance with PG&E Energy Services to bring the benefits of these services to its members. Through the Council's load aggregation program – one of the largest in the country – PG&E

Wisconsin Electric, a subsidiary of Wisconsin Energy Corporation, provides electricity, natural gas, and/or steam to more than 2.3 million people in Wisconsin and Michigan. To ensure competitive prices for its customers, this forward-looking utility is maximizing the value of its energy assets by tapping the expertise of PG&E Energy Trading. Bob Harrington, account manager, PG&E Energy Trading, shown here, left, and Tim McCollow, manager, gas supply, Wisconsin Electric, discuss how excess supply, transportation capacity, and storage inventory can be managed to ultimately realize cost savings for Wisconsin Electric's customers.

WISCONSIN ELECTRIC

Milwaukee, Wisconsin

We bring the benefits of the competitive, national energy marketplace to each of our customers.

Energy Services is providing power and other energy-related services to high technology companies throughout Massachusetts, including such leading firms as Hewlett-Packard, Data General, EMC Corporation, and Varian Associates. And the electricity delivered to these companies originates from power plants owned by USGen – a prime example of the synergy of PG&E Corporation's subsidiaries working to serve customers nationwide.

A Future of Possibilities

PG&E Corporation's unregulated businesses face a rich frontier. The market for electricity, natural gas, and related services in the United States today is worth more than $400 billion a year, and our domestic energy strategy gives us a clear focus on a future of possibilities.

The growth we accomplished in 1998, along with the profits we generated for shareholders, demonstrate that our unregulated subsidiaries will be able to build on that strategy well into the next century.

Profits and progress today, a wealth of opportunities for tomorrow. Through our unregulated businesses, PG&E Corporation is giving shareholders both. It's a winning combination.

Directors

Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company[1]

RICHARD A. CLARKE
Chairman of the Board, Retired,
Pacific Gas and Electric Company

HARRY M. CONGER
Chairman of the Board and
Chief Executive Officer, Emeritus,
Homestake Mining Company

DAVID A. COULTER
Former Chairman and
Chief Executive Officer,
BankAmerica Corporation and
Bank of America NT&SA

C. LEE COX
Vice Chairman, Retired,
AirTouch Communications, Inc.
and President and Chief Executive
Officer, Retired, AirTouch Cellular

WILLIAM S. DAVILA
President Emeritus,
The Vons Companies, Inc.
(retail grocery)

ROBERT D. GLYNN, JR.
Chairman of the Board,
Chief Executive Officer, and
President, PG&E Corporation
and Chairman of the Board,
Pacific Gas and Electric Company

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Officer, Kaiser Foundation Health
Plan, Inc. and Kaiser Foundation
Hospitals

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Chief Executive Officer, Retired,
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(diversified forest products)

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REBECCA Q. MORGAN
President and Chief Executive
Officer, Retired, Joint Venture:
Silicon Valley Network
(non-profit collaborative addressing
critical issues facing Silicon Valley)

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

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

ALAN SEELENFREUND[2]
Chairman of the Board and
Chief Executive Officer, Retired,
McKesson Corporation
(distributor of pharmaceuticals
and health care products)

GORDON R. SMITH[1]
President and
Chief Executive Officer,
Pacific Gas and Electric Company

BARRY LAWSON WILLIAMS
President,
Williams Pacific Ventures, Inc.
(business consulting and mediation)

Permanent Committees of PG&E Corporation and Pacific Gas and Electric Company[3]

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

Robert D. Glynn, Jr., Chair
Harry M. Conger
Richard B. Madden
Mary S. Metz
Carl E. Reichardt
Gordon R. Smith[3]

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

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

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

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

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

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

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

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

[1] The composition of the Boards of Directors is the same, except that Gordon R. Smith is a Director of the Pacific Gas and Electric Company Board of Directors only.
[2] Retired as a director of PG&E Corporation and Pacific Gas and Electric Company on January 27, 1999.
[3] The committee membership shown is effective April 1, 1999. Except for the Executive Committee, all Committees listed above are committees of the PG&E Corporation Board of Directors. The Executive Committees of the PG&E Corporation and Pacific Gas and Electric Company Boards have the same members, except that Gordon R. Smith is a member of the Pacific Gas and Electric Company Executive Committee only.

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Chief Executive Officer, and
President

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Senior Vice President,
Corporate Development

Scott W. Gebhardt
Senior Vice President

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

P. Chrisman Iribe
Senior Vice President

Thomas B. King
Senior Vice President

L. E. Maddox
Senior Vice President

Michael E. Rescoe
Senior Vice President,
Chief Financial Officer, and
Treasurer

Gordon R. Smith
Senior Vice President

G. Brent Stanley
Senior Vice President,
Human Resources

Bruce R. Worthington
Senior Vice President and
General Counsel

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Vice President and
Corporate Secretary

Christopher P. Johns
Vice President and
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Federal Governmental and
Regulatory Relations

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Business Planning

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Corporate Communications

Daniel D. Richard, Jr.
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Governmental Relations

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Supply Business Unit

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Distribution and Customer Service
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M. Richard Smith
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Public Affairs and
Government Relations

James M. Richter
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U.S. Generating Company

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Senior Vice President and
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Dale A. Murdock
Senior Vice President,
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Vice President and
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Vice President and
General Counsel

Gay Westfall
Vice President,
Human Resources

*Officers of PG&E Corporation and officers reporting directly to presidents of the principal subsidiaries.

Selected Financial Data

(in millions, except per share amounts)	1998	1997	1996	1995	1994
PG&E Corporation[1]					
For the Year					
Operating revenues	$19,942	$15,400	$ 9,610	$ 9,622	$10,350
Operating income	2,007	1,728	1,896	2,763	2,424
Net income	719	716	722	1,269	950
Earnings per common share	1.88	1.75	1.75	2.99	2.21
Dividends declared per common share	1.20	1.20	1.77	1.96	1.96
At Year-End					
Book value per common share	$ 21.08	$ 21.30	$ 20.73	$ 20.77	$ 20.07
Common stock price per share	31.50	30.31	21.00	28.38	24.38
Total assets	33,234	31,115	26,237	26,871	27,738
Long-term debt (excluding current portions)	7,422	7,659	7,770	8,049	8,676
Rate reduction bonds (excluding current portions)	2,321	2,611	—	—	—
Redeemable preferred stock and securities of subsidiaries (excluding current portions)	635	750	694	694	725
Pacific Gas and Electric Company					
For the Year					
Operating revenues	$ 8,924	$ 9,495	$ 9,610	$ 9,622	$10,350
Operating income	1,876	1,831	1,896	2,763	2,424
Income available for common stock	702	735	722	1,269	950
At Year-End					
Total assets	$22,950	$25,147	$26,237	$26,871	$27,738
Long-term debt (excluding current portions)	5,444	6,218	7,770	8,049	8,676
Rate reduction bonds (excluding current portions)	2,321	2,611	—	—	—
Redeemable preferred stock and securities (excluding current portions)	579	694	694	694	725

[1] PG&E Corporation became the holding company for Pacific Gas and Electric Company on January 1, 1997. The Selected Financial Data of PG&E Corporation and Pacific Gas and Electric Company (the Utility) for the years 1994 through 1996 are identical because they reflect the accounts of the Utility as the predecessor of PG&E Corporation. Matters relating to certain data above are discussed in Management's Discussion and Analysis and in Notes to the Consolidated Financial Statements.

PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's businesses provide energy services throughout North America. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company (the Utility), provides natural gas and electric service to one of every 20 Americans. PG&E Corporation's four unregulated businesses provide a wide range of energy products and services through its wholesale and retail unregulated business operations.

PG&E Corporation's wholesale unregulated business operations consist of U.S. Generating Company (USGen) which develops, builds, operates, owns, and manages power generation facilities that serve wholesale and industrial customers; PG&E Gas Transmission (PG&E GT) which operates approximately 9,000 miles of natural gas pipelines, natural gas storage facilities, and natural gas processing plants in the Pacific Northwest (PG&E GT NW) and Texas (PG&E GTT); and PG&E Energy Trading (PG&E ET) which purchases and resells energy commodities and related financial instruments in major North American markets, serving PG&E Corporation's other unregulated businesses, unaffiliated utilities, and large end-use customers.

PG&E Corporation's retail unregulated business operations consist of PG&E Energy Services (PG&E ES) which provides competitively priced electricity, natural gas, and related services to lower overall energy costs for industrial, commercial, and institutional customers.

This is a combined annual report of PG&E Corporation and Pacific Gas and Electric Company. It includes separate consolidated financial statements for each entity. The consolidated financial statements of PG&E Corporation reflect the accounts of PG&E Corporation, the Utility, and PG&E Corporation's other wholly owned and controlled subsidiaries. The consolidated financial statements of the Utility reflect the accounts of the Utility and its wholly owned subsidiaries.

PG&E Corporation was formed in 1997 as the parent holding company for the Utility and the unregulated businesses. Information for 1996 in PG&E Corporation's consolidated financial statements is identical to information in the Utility's consolidated financial statements because they represent the accounts of Utility as the predecessor of PG&E Corporation.

This combined annual report, including our Letter to Shareholders and this Management's Discussion and Analysis (MD&A), contains forward-looking statements about the future that are necessarily subject to various risks and uncertainties. These statements are based on the beliefs and assumptions of management and on information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," and other similar expressions.

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

- the pace and extent of the ongoing restructuring of the electric and gas industries across the United States;
- the outcome of regulatory and legislative proceedings and operational changes related to industry restructuring;
- any changes in the amount the Utility is allowed to collect (recover) from its customers for certain costs which prove to be uneconomic under the new competitive market (called transition costs) in accordance with the Utility's plan for recovering those costs;
- the successful integration and performance of our recently acquired assets;
- our ability to successfully compete outside our traditional regulated markets;
- internal and external Year 2000 software and hardware issues;
- the outcome of ongoing regulatory proceedings, including: the Utility's cost of capital proceeding; the Utility's 1999 general rate case; the Utility's proposal to adopt performance based ratemaking (PBR); the Utility's transmission rate case applications; and the California Public Utilities Commission's (CPUC) regulatory proceedings including its audit of the Utility's affiliate transactions;
- fluctuations in commodity gas and electric prices and our ability to successfully manage such price fluctuations; and
- the pace and extent of competition in the California generation market and its impact on the Utility's costs and resulting collection of transition costs.

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

In this MD&A, we first discuss our competitive and regulatory environment. We then discuss earnings and changes in our results of operations for 1998, 1997, and 1996. Finally, we discuss liquidity and financial resources, various uncertainties that could affect future earnings, and our risk management activities. Our MD&A applies to both PG&E Corporation and the Utility. The MD&A should be read in conjunction with the associated consolidated financial statements of both PG&E Corporation and the Utility.

Competitive and Regulatory Environment

This section provides a discussion of the competitive environment in the evolving energy industry, the California transition plans, the New England electricity market, and regulatory matters.

The Competitive Environment in the Evolving Energy Industry

Historically, energy utilities operated as regulated monopolies within specific service territories where they were essentially the sole suppliers of natural gas and electricity services. Under this model, the energy utilities owned and operated all of the businesses necessary to procure, generate, transport, and distribute energy. These services were priced on a combined (bundled) basis, with rates charged by the energy companies designed to include all of the costs of providing these services. Now, energy utilities face intensifying pressures to make competitive those activities that are not natural monopoly services. The most significant of these services are electricity generation and natural gas supply.

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

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

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

To date, the states, not the federal government, have taken the initiative on electric industry restructuring at the retail level. While at least five bills mandating deregulation of the electric industry were introduced in the U.S. Congress over the past two years, none have been passed. As a result, the pace, extent, and methods for restructuring the electric industry vary widely throughout the country. For instance, California, Illinois, Pennsylvania, and several New England states have passed electric industry restructuring legislation. Other states are considering restructuring proposals. There are also some states that have passed legislation precluding or significantly slowing down deregulation. Differences in how individual states view electric industry restructuring often relate to the existing unit cost of energy supplies within each state. Generally, states having higher energy unit costs are moving more quickly to deregulate energy supply markets.

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

California Transition Plans

The Electric Business:

In 1998, California became one of the first states in the country to implement an electric industry restructuring plan. Today, many Californians may choose to purchase their electricity from (1) investor-owned utilities such as Pacific Gas and Electric Company, or (2) unregulated retail electricity suppliers (for example, marketers, including PG&E Energy Services, brokers, and aggregators). The restructuring plan contemplates that the investor-owned utilities, including the Utility, will continue to provide distribution services to substantially all customers within their service territories, including providing electricity to customers who choose not to be served by another service provider. California electric industry restructuring has two major components: the competitive market framework and the electric transition plan, which are discussed below.

Competitive Market Framework:

To create a competitive generation market, a Power Exchange (PX) and an Independent System Operator (ISO) began operating in 1998. The Utility is required to sell to the PX all of the electricity generated by its power plants and electricity acquired under contract with unregulated generators. Also, the Utility is required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier. The ISO schedules delivery of electricity for all market participants to the transmission system. The Utility continues to own and maintain a portion of the transmission system, but the ISO controls the operation of the system.

During 1998, the Utility continued its efforts to develop and implement changes to its business processes and systems, including the customer information and billing system, to accommodate electric industry restructuring. To the extent that the Utility is unable to develop and implement such changes in a successful and timely manner, there could be an adverse impact on the Utility's or PG&E Corporation's future results of operations.

Electric Transition Plan:

Market-based revenues, determined by the market through sales to the PX, may not be sufficient to recover (that is, to collect from customers) all of the Utility's generation costs. To allow California investor-owned utilities the opportunity to recover their transition costs (generation costs that would not be recovered through market-based revenues) and to ensure a smooth transition to a competitive market, the California legislature developed a transition plan in the form of state legislation that was passed in 1996. The transition plan will remain in effect until the earlier of December 31, 2001, or when the Utility has recovered its authorized transition costs as determined by the CPUC, with provisions that certain transition costs can be recovered after the transition period. At the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues. The transition plan contains three principal elements: (1) an electric rate freeze and rate reduction, (2) the recovery of transition costs, and (3) divestiture of utility-owned generation facilities. Each element is discussed below.

Rate Freeze and Rate Reduction: The first element of the transition plan is an electric rate freeze and an electric rate reduction. In 1997 and 1998, the Utility held rates for its larger customers at 1996 levels, and it will hold their rates at that level until the end of the transition period. On January 1, 1998, the Utility reduced electric rates for its residential and small commercial customers by 10 percent from 1996 levels, and it will hold their rates at that level until the end of the transition period. Collectively, these actions are called a rate freeze.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion of its transition costs with the proceeds of rate reduction bonds (see Note 9 of Notes to Consolidated Financial Statements). The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period.

Transition costs are being recovered from all Utility distribution customers through a nonbypassable charge regardless of the customer's choice of electricity supplier. As the customer charge for transition costs is nonbypassable, the Utility believes that the availability of choice to its customers will not have a material impact on its ability to recover transition costs.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, and nuclear decommissioning. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the competitive transition charge (CTC) which recovers the transition costs. These CTC revenues are subject to seasonal fluctuations in the Utility's sales volumes and certain other factors.

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

Above-market sunk costs result when the book value of a facility is in excess of its market value. Conversely, below-market sunk costs result when the market value of a facility is in excess of its book value. The total amount of generation facility costs to be included as transition costs will be based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. A valuation of a Utility-owned generation facility where the market value exceeds the book value could result in a material charge to Utility earnings if the valuation of the facility is determined based upon any method other than a sale of the facility to a third party. This is because any excess of market value over book value would be used to reduce other transition costs.

The Utility will not be able to determine the exact amount of above-market non-nuclear sunk costs that will be recoverable as transition costs until a market valuation process (appraisal, spin, sale, or other valuation method) is completed for each of its generation facilities. Several of these valuations occurred in 1997 and 1998, when the Utility agreed to sell seven of its electric plants. The market value of these facilities determined by these sales exceeded the book value and will therefore reduce the amount of transition costs to be recovered. In addition, in December 1998, the Utility requested that the CPUC allow it to hire appraisers to set the value of its hydroelectric generation system. (See Generation Divestiture below.) The remainder of the valuation process is expected to be completed by December 31, 2001. Nuclear sunk costs were separately determined through a CPUC proceeding and were subject to a final verification audit. This audit was completed in August 1998, the results of which are currently under review. (See Regulatory Matters below for further details.)

Costs associated with the Utility's long-term contracts to purchase electric power at above-market prices are included as transition costs. Over the remaining life of these contracts, the Utility estimates that it will purchase 322 million megawatt-hours. To the extent that the individual contract prices are above the market price, the Utility will be able to collect the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. The contracts expire at various dates through 2028. During 1998, the average price paid per kilowatt-hour (kWh) under the Utility's long-term contracts for electric power was 7.4 cents per kWh. The average cost of electric energy for energy purchased at market rates from the PX for the period from April 1, 1998, to December 31, 1998, was 3.2 cents per kWh.

Generation-related regulatory assets and obligations (net generation-related regulatory assets) are included as transition costs. These net regulatory assets consist of those created prior to the transition period and those created during the transition period. In 1998, the staff of the Securities and Exchange Commission (SEC) issued interpretive guidance related to assets which are being transitioned to a deregulated environment. The guidance states that an impairment analysis should be performed for such assets and that the impairment analysis should exclude transition cost revenues. The Utility has determined that certain of its generation facilities are considered impaired under the SEC's interpretive guidance. Because the Utility expects to recover the impaired assets as a transition cost, it recorded a regulatory asset for the impaired amounts as required. As a result, in 1998, $3.9 billion was reclassified from property, plant, and equipment to regulatory assets on the Utility's balance sheet. Prior year amounts were also reclassified. The Utility's generation-related regulatory assets total $5.4 billion at December 31, 1998.

Under the transition plan, most transition costs can be recovered until December 31, 2001. This recovery period is significantly shorter than the recovery period of the generation assets prior to restructuring and is referred to as accelerated recovery. Accordingly, the Utility is amortizing its transition costs, including most generation-related regulatory assets over the transition period. The CPUC believes that the transition plan reduces risks associated with recovery of all the Utility's generation assets, including the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the hydroelectric facilities. As a result, during the transition period, the Utility is receiving a reduced return on common equity for all of its generation assets, including those generation assets reclassified to regulatory assets. In 1998, the reduced return on common equity was 6.77 percent as compared to an authorized return on common equity of 11.20 percent. The reduced return on common equity related to generation assets will be in effect throughout the transition period.

Certain transition costs can be included in a nonbypassable charge to distribution customers after the transition period. These costs include: (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, and (3) unrecovered electric industry restructuring implementation costs. In addition, transition costs financed by the issuance of rate reduction bonds are expected to be recovered over the term of the bonds. Further, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission our nuclear facility. During the rate freeze, this charge and the rate reduction bond debt service will not increase the Utility customers' electric rates. Excluding these exceptions, the Utility will write-off any transition costs not recovered during the transition period.

Under the terms of the transition plan, revenues provided for the recovery of most non-nuclear transition costs are based upon the acceleration of such costs within the transition period. For nuclear transition costs, revenues provided for transition cost recovery are based on: (1) an established incremental cost incentive price per kWh generated by Diablo Canyon to recover certain ongoing costs and capital additions, and (2) the accelerated recovery of the investment in Diablo Canyon from a period ending in 2016 to a five-year period ending December 31, 2001.

The Utility is amortizing its eligible transition costs, including generation-related regulatory assets, over the transition period in conjunction with the available CTC revenues. Effective January 1, 1998, the Utility started collecting these eligible transition costs through the nonbypassable CTC. During 1998, regulatory assets related to electric utility restructuring decreased by $609 million. This decrease reflects the recovery of eligible transition costs of $486 million through accelerated amortization and $123 million through the gain on the sale of generating plants.

During the transition period, the CPUC will review the Utility's compliance with the accounting methods used by the Utility to recover transition costs and the amount of transition costs requested for recovery. The CPUC is currently reviewing non-nuclear transition costs amortized during the first six months of 1998. The Utility expects the CPUC to issue decisions regarding this review in the second half of 1999. Transition costs that are disallowed by the CPUC for collection from the Utility customers will be written off.

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

Also in 1998, the Utility agreed to sell three other fossil-fueled generation plants and its complex of geothermal generation facilities. The winning bids total $1,014 million. As of December 31, 1998, these four plants had a combined book value of $523 million and had a combined capacity of 4,289 MW. The sales are subject to the approval of regulatory agencies, including the CPUC, and conditioned upon the transfer of various permits and licenses. The Utility expects to complete the sale of these four plants in 1999.

The Utility will retain a liability for required environmental remediation related to all of its fossil-fueled and geothermal generation plants of any pre-closing soil or groundwater contamination at the plants it has or will sell. The Utility records its estimated liability for the retained environmental remediation obligation as part of the determination of the gain or loss on the sale of each plant.

Any net gains from the sale of our Utility-owned generation plants will be used to offset other transition costs. As a result, we do not believe sales of any generation facilities to a third party will have a material impact on our results of operations.

The Utility is currently evaluating its options related to its remaining non-nuclear generation facilities, primarily the hydroelectric generation system. In May 1998, the Utility notified the CPUC that it does not plan to retain the hydroelectric assets as part of the Utility. In December 1998, the Utility filed with the CPUC its proposed appraisal process for valuing generation assets, primarily the hydroelectric system. The Utility expects to receive a response to this request in 1999.

At December 31, 1998, the book value of the Utility's net investment in hydroelectric generation assets was $1.4 billion. If the Utility decides to dispose of the hydroelectric generation assets by any method other than a sale of the assets to a third party, a material charge could result to the extent that the market value of the assets exceeds their book value. The market value of the hydroelectric assets is expected to exceed their book value by a material amount.

Financial Impact: The Utility's ability to continue recovering its transition costs will be dependent on several factors including: (1) the continued application of the regulatory framework established by the CPUC and state legislation, (2) the amount of transition costs ultimately approved for recovery by the CPUC, (3) the market value of the remaining Utility-owned generation facilities, (4) future Utility sales levels, (5) future Utility fuel and operating costs, (6) the extent to which the Utility's authorized revenues to recover distribution costs are increased or decreased (see Regulatory Matters), and (7) the market price of electricity. Given our current evaluation of these factors, we believe that the Utility will recover its transition costs under the terms of the approved transition plan. However, a change in one or more of these factors could affect the probability of recovery of transition costs and result in a material charge.

The Gas Business:

Restructuring of the natural gas industry on both the national and the state level has given choices to California utility customers to meet their gas supply needs. The Gas Accord Settlement (Accord), a multiparty settlement approved by the CPUC in 1997, continues the process of restructuring the gas industry in California. The Accord was implemented in 1998, and has four principal elements:

1. The Accord separates or "unbundles" the rates for the Utility's gas transportation system. The Utility now offers transmission, distribution, and storage services as separate and distinct services to its noncore customers. Unbundling gives these customers the opportunity to select from a menu of services offered by the Utility and enables them to pay only for the services that they use. Unbundling also makes access to the transmission system possible for all gas marketers and shippers, as well as noncore end-users. As a result, the Accord makes the Utility's transmission system more accessible to a greater number of customers.
2. The Accord increases the opportunity for the Utility's core customers to select the commodity gas supplier of their choice. Greater customer choice increases competition among suppliers providing gas to core customers and reduces the Utility's role in purchasing gas for such customers. Despite these changes, the Utility continues to purchase gas as a regulated supplier for those who request it, serving a majority of core customers in its service territory.

3. The Accord changes the way in which the Utility's costs of purchasing gas for core customers through 2002 are regulated. The Accord replaces CPUC reasonableness reviews with the core procurement incentive mechanism (CPIM), a form of incentive ratemaking that provides the Utility a direct financial incentive to procure gas and transportation services at the lowest reasonable costs by comparing all procurement costs to an aggregate market-based benchmark. If costs fall within a range (tolerance band) around the benchmark, costs are considered reasonable and fully recoverable from ratepayers. If procurement costs fall outside the tolerance band, ratepayers and shareholders share savings or costs, respectively. The CPIM results for 1997 and 1998 had an immaterial impact on the Utility's results of operations.
4. The Accord settled various regulatory issues involving the Utility and various other parties. Resolution of these issues did not have a material adverse impact on the Utility's or our financial position or results of operations.

The Accord also establishes gas transmission rates within California for the period from March 1998 through December 2002 for the Utility's core and noncore customers and eliminates regulatory protection for variations in sales volumes for noncore transmission revenues. As a result, the Utility is at risk for variations between actual and forecasted noncore transmission throughput volumes. However, we do not expect these variations to have a material adverse impact on the Utility's or our financial position or results of operations.

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

New England Electricity Market

Three New England states where our unregulated businesses operate electric generation facilities (Massachusetts, New Hampshire, and Rhode Island) were, like California, among the first states in the country to introduce electric industry restructuring. Connecticut also has passed electric industry restructuring legislation. As a result of this restructuring, the wholesale unregulated electricity market in New England features a bid-based market and an independent system operator.

In September 1998, PG&E Corporation, through its indirect subsidiary USGen New England, Inc., completed the acquisition of a portfolio of electric generation assets and power supply contracts from New England Electric System (NEES). (See Note 5 of Notes to Consolidated Financial Statements.) The NEES assets include hydroelectric, coal, oil, and natural gas generation facilities with a combined generating capacity of about 4,000 MW.

Including fuel and other inventories and transaction costs, the financing requirements for this transaction were approximately $1.8 billion, funded through $1.3 billion of USGen debt and a $425 million equity contribution from PG&E Corporation. The net purchase price has been allocated as follows: (1) electric generating assets of $2.3 billion, (2) receivable for support payments of $0.8 billion, and (3) contractual obligations of $1.3 billion.

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

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

In connection with the purchase of the generation assets, we entered into agreements to supply the electric capacity and energy requirements necessary for NEES to meet its SOS obligations. NEES is responsible for passing on to us the revenues generated from the SOS.

Like California utilities, the New England utilities entered into agreements with unregulated companies to provide energy and capacity at prices which are anticipated to be in excess of market prices. We assumed NEES's contractual rights and duties under several of these power-purchase agreements, which in aggregate provide for 800 MW of capacity. However, NEES will make support payments to us toward the cost of these agreements. The support payments by NEES total $1.1 billion in the aggregate (undiscounted) and are due in monthly installments from September 1998 through January 2008. In certain circumstances, with our consent, NEES may make a full or partial lump sum accelerated payment.

Initially, approximately 90 percent of the acquired operating capacity, including capacity and energy generated by other companies and provided to us under power-purchase agreements, is dedicated to providing services to customers receiving SOS.

Regulatory Matters

The Utility is the only subsidiary with significant regulatory activity at this time. Items affecting future Utility authorized revenues include: the 1999 general rate case, the 1999 cost of capital proceeding, the distribution performance based ratemaking application, and the CPUC's gas strategy order instituting rulemaking. These items are discussed below. Any requested change in authorized revenues resulting from any of these proceedings would not impact the Utility's customer electric rates through the transition period because these rates are frozen in accordance with the electric transition plan. However, the amount of remaining revenues providing for the recovery of transition costs would be affected.

The Utility's 1999 General Rate Case (GRC):
In December 1997, the Utility filed its 1999 GRC application with the CPUC. During the GRC process, the CPUC examines the Utility's distribution costs to determine the amount we can charge customers. The Utility has requested rate increases to maintain and improve gas and electric distribution reliability, safety, and customer service. The requested revenues, as updated, include an increase of $445 million in electric base revenues and an increase of $377 million in gas base revenues over authorized 1998 revenues. The Office of Ratepayer Advocates (ORA) branch of the CPUC has recommended a decrease of $80 m[illegible] electric revenues and an increase of $104 mili[illegible] as base revenues. However, recommendations by the ORA do not represent the positions of the CPUC.

In December 1998, the CPUC issued a decision on interim rate relief in the GRC. The decision granted the Utility's request to increase its electric revenues by $445 million and its gas revenues by $377 million on an interim basis pending a decision in the GRC. The decision allows the Utility to reflect the revenue increases, resulting from the Utility request, in regulatory assets recorded under regulatory adjustment mechanisms approved by the CPUC. The decision does not increase any electric or gas rates charged to customers on an interim basis. The regulatory assets will be adjusted to reflect the final decision of the CPUC in the 1999 GRC when the decision is issued. We cannot predict the amount of revenue increase or decrease the CPUC ultimately will approve. If the CPUC issues an unfavorable decision for the Utility, the ability of the Utility to earn its authorized rate of return, at the current service levels, for the years 1999 through 2001 could be adversely affected. The current procedural schedule provides for a final CPUC decision in March 1999.

The 1999 GRC will not affect the authorized revenues of electric and gas transmission services or gas storage services. The authorized revenues for gas transmission and storage services are determined through the Gas Accord and electric transmission revenues are determined by the FERC as described below.

Electric Transmission:
Since April 1, 1998, all electric transmission revenues are authorized by the FERC. In December 1997, the FERC issued an order which put into effect, subject to refund, rates to recover annual electric transmission revenues of $301 million from the Utility's former

bundled rate transmission customers. These rates became effective on April 1, 1998, the operational date of the ISO and PX. In May 1998, the FERC allowed a $30 million increase in electric transmission revenues, effective October 30, 1998, also subject to refund.

The Utility's 1999 Cost of Capital Proceeding: The Utility filed its cost of capital application in May 1998. If approved, the authorized return on rate base for distribution assets would be 9.53 percent. The 1999 cost of common equity would be 12.1 percent which is higher than the 11.2 percent authorized in 1998. This request would result in an increase of $49.7 million in electric distribution revenues and an increase of $15.5 million in gas distribution revenues over authorized 1998 revenues.

The ORA has recommended an overall return on rate base for electric and gas distribution operations of 7.85 and 8.17 percent, respectively, and a cost of common equity of 8.64 and 9.32 percent, respectively. If adopted, the ORA's recommendation would result in a decrease from authorized 1998 revenues in electric and gas distribution revenues of $162.5 million and $37.8 million, respectively. However, recommendations by the ORA do not represent the positions of the CPUC. We expect a final CPUC decision in early 1999.

The Utility's Distribution Performance Based Ratemaking (PBR) Application: The Utility filed its distribution PBR proposal in November 1998. If approved as filed, the distribution PBR will determine the Utility's gas and electric distribution revenues for the years 2000 through 2004. Under the Utility's proposal, distribution revenues for the year 2000 would be determined by multiplying total distribution revenues by a rate formula, based principally on inflation less a proposed productivity factor of 1.1 percent and 0.82 percent for electric distribution and gas distribution, respectively. These productivity factors will be fixed for the five year duration of the PBR. The revenues for years 2000 through 2004 would be determined by multiplying total distribution revenues by the PBR authorized rate. We have proposed different formulas for small customers (principally residential and commercial customers) and large customers.

The proposal also includes a sharing mechanism for earnings that are significantly above or below the authorized weighted average cost of capital. In addition, the proposed PBR includes rewards and penalties that will depend upon the Utility's ability to achieve performance standards for electric distribution reliability; maintenance, repair, and replacement; customer service; and employee safety. The Commission will have hearings in the PBR proceeding in August 1999 to determine adopted values for the PBR formula and sharing parameters. The final schedule is uncertain, but a Commission decision is expected after January 1, 2000. In this event, the Utility proposes to implement the PBR-based distribution component rates retroactively to January 1, 2000.

The CPUC's Gas Strategy Order Instituting Rulemaking (OIR): In 1998, the Governor of California signed Senate Bill 1602, allowing the CPUC to investigate issues associated with the further restructuring of natural gas services. If the CPUC determines that further restructuring for core customers is in the public interest, it shall submit its findings to the Legislature. However, Senate Bill 1602 prohibits the CPUC from enacting any such gas industry restructuring decisions prior to January 1, 2000.

The CPUC's Audit of Affiliate Transactions: PG&E Corporation became the holding company of the Utility in 1997. At that time, we transferred the unregulated subsidiaries of the Utility to PG&E Corporation. A condition of the CPUC's approval of the holding company formation was that the ORA oversee an audit of transactions between the Utility and its affiliates for the period 1994 to 1996. The audit was completed in November 1997. The principal claim in the resulting audit report, substantially denied by the Utility, was that the Utility underbilled affiliates by $35 million during the period from 1994 to 1996. The auditors recommended the CPUC impose new conditions, affecting the financing and business structure of PG&E Corporation. We are opposing the recommended new conditions. A final CPUC decision is expected during the first quarter of 1999.

If the CPUC imposed the recommended financial conditions on PG&E Corporation without modification, such conditions could have an adverse impact on our ability to implement our national energy strategy.

The Diablo Canyon Sunk Costs Audit:
In August 1998, an independent accounting firm retained by the CPUC completed a financial verification audit of the Utility's Diablo Canyon plant accounts as of December 31, 1996. The audit resulted in the issuance of an unqualified opinion. The audit verified that Diablo Canyon sunk costs at December 31, 1996, were $3.3 billion of the total $7.1 billion construction costs. (Sunk costs are costs associated with Utility-owned generating facilities that are fixed and unavoidable and currently included in the Utility customers' electric rates.) The independent accounting firm also issued an agreed-upon special procedures report which questioned $200 million of the $3.3 billion sunk costs. The CPUC will review any proposed adjustments to Diablo Canyon's recoverable costs, which resulted from the report. At this time, the Utility cannot predict what actions, if any, the CPUC may take regarding the audit report.

Results of Operations
In this section, we present the components of our results of operations for 1998, 1997, and 1996. The table below shows for 1998, 1997, and 1996, certain items from our Statement of Consolidated Income detailed by (1) Utility, (2) wholesale and (3) retail business operations of PG&E Corporation. (In the "Total" column, the table shows the combined results of operations for these three groups.) The information for PG&E Corporation (the "Total" column) excludes all transactions between its subsidiaries (such as the purchase of natural gas by the Utility from the unregulated business operations). Following this table we discuss earnings and explain why the components of our results of operations varied from the year before for 1998 and 1997.

		Wholesale							
			PG&E GT						
(In millions)	Utility	USGen	NW	Texas	PG&E ET	PG&E ES	Corp./Other	Eliminations	Total
1998									
Operating revenues	$8,924	$649	$237	$1,941	$8,509	$379	$ 8	$(705)	$19,942
Operating expenses	7,048	489	101	1,996	8,528	470	3	(700)	17,935
Operating income (loss)	1,876	160	136	(55)	(19)	(91)	5	(5)	2,007
Other income, net									64
Interest expense									782
Income taxes									570
Net income									$ 719
1997									
Operating revenues	9,495	$148	$233	$1,004	$4,808	$145	$ 13	$(446)	$15,400
Operating expenses	7,664	176	127	1,023	4,840	190	98	(446)	13,672
Operating income (loss)	1,831	(28)	106	(19)	(32)	(45)	(85)	—	1,728
Other income, net									201
Interest expense									665
Income taxes									548
Net income									$ 716
1996									
Operating revenues	$8,989	$105	$264	$ —	$ 283	$ —	$ 27	$ (58)	$ 9,610
Operating expenses	7,179	118	136	—	283	—	56	(58)	7,714
Operating income (loss)	1,810	(13)	128	—	—	—	(29)	—	1,896
Other income, net									13
Interest expense									632
Income taxes									555
Net income									$ 722

Overall Results:

PG&E Corporation:

Net income increased to $719 million in 1998 from $716 million in 1997. The increase in 1998 net income was the result of a $279 million increase in operating income, net of lower returns on the Utility's generation assets. This increase was offset partially by increased interest costs for the Utility's rate reduction bonds and debt associated with the recent unregulated wholesale acquisitions of assets in Texas and New England.

The operating income increase of $279 million was primarily due to the growth of our wholesale and retail operations which contributed $149 million of the increase. This operating income increase was achieved despite operating losses at PG&E ES and PG&E GTT. USGen contributed positively to operating income which includes income generated from its portfolio management activities.

The operating losses at PG&E ES reflect the continued start-up operations and the impact of the developing retail energy market. At PG&E GTT, the natural gas liquids operations have been adversely affected by the low price differential between natural gas liquids (NGLs) prices and the cost of natural gas, which is used to produce NGLs. In addition, low gas prices and a narrow spread in the price of gas transported across Texas have reduced PG&E GTT's transportation and gas sales.

The 1998 net income also includes a loss on the sale of our Australian energy holdings. The sale represented a significant premium in Australian currency of PG&E Corporation's 1996 investment in the assets. However, there was a 22 percent currency devaluation of the Australian dollar against the U.S. dollar during the past two years. The net transaction resulted in a charge of approximately $23 million in the second quarter of 1998. (See Note 5 of Notes to Consolidated Financial Statements.)

Net income decreased from $722 million in 1996 to $716 million in 1997. The 1997 net income includes charges of approximately $51 million associated with the write off of investments in power generation projects at USGen, which were offset by the gain realized on the sale of our interests in International Generation Company, Ltd. In April 1997, PG&E Enterprises, a wholly owned subsidiary of PG&E Corporation, sold its interest in International Generating Company, Ltd., which resulted in an after-tax gain of $120 million.

Utility:

Net income for the Utility decreased $39 million in 1998 from 1997 due to the reduced rate of return on generation assets and increased interest expense associated with the rate reduction bonds, discussed below.

Net income for the Utility increased $13 million in 1997 from 1996. Net income for 1997 included a gain on the buy out of a long-term gas contract. The increase in 1997 is also related to the increase in revenues associated with electric transmission and distribution system reliability, discussed below. This increase is partially offset by the reduction in returns on the Utility's Diablo Canyon facility as required by electric industry restructuring legislation and spending for system reliability and safety.

Operating Revenues:

Utility:

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

Utility operating revenues in 1997 increased $506 million from 1996. The largest portion of the increase was due to electric transition cost recovery, which began January 1, 1997, with respect to Diablo Canyon. A portion of the increase is due to increased revenues associated with electric transmission and distribution system reliability. There was also an increase in energy cost revenues to recover energy cost increases and changes in sales volumes provided by the Utility's balancing account mechanisms in place in 1997 and 1996. Under these mechanisms, energy revenues generally equal energy costs and, thus, increases in the cost of energy do not affect operating income.

Wholesale Unregulated Business Operations:
Operating revenues associated with wholesale unregulated business operations increased $5,143 million in 1998 from 1997. This was primarily due to revenue increases of $3,701 million from PG&E ET, $937 million from PG&E GTT and $501 million from USGen. Energy trading volumes grew at [illegible] ET as growth of PG&E Corporation and deregulation of the energy markets continued. PG&E GTT's revenues increased as a result of twelve months of revenue from the Texas acquisitions versus seven months in 1997. USGen's revenue increased as a result of an increase in the portfolio management activity and the acquisition of NEES in 1998.

Operating revenues associated with wholesale unregulated business operations increased $5,541 million in 1997 from 1996. This was primarily due to a $4,525 million increase in energy commodities revenues and an increase in revenues resulting from our 1997 acquisitions.

Retail Unregulated Business Operations:
Retail unregulated business operations contributed $379 million of revenue in 1998, an increase of $234 million from 1997. This increase is primarily due to deregulation in California and the expansion of our energy services business in the electric and gas commodity markets.

Operating revenues associated with retail unregulated business operations totaled $145 million in 1997, the first year of operation.

Operating Expenses:

Utility:
Utility operating expenses in 1998 decreased $616 million from 1997. This decrease reflects a reduction in the amount of amortization of transition costs, primarily due to lower revenues from residential and small commercial customers discussed above in Operating Revenues-Utility. Also contributing to the decrease in operating expenses was a reduction in gas transportation demand charges of $134 million, due to the expiration of contracted pipeline capacity.

Utility operating expenses in 1997 increased $485 million from 1996. The increase was due primarily to an increase in amortization of Diablo Canyon costs which are being recovered as a transition cost as discussed above, an increase in cost of energy, and an increase in expenditures associated with system reliability. These increases were partially offset by a decrease in expenses resulting from several charges in 1996 associated with gas transportation commitments and a litigation reserve.

Wholesale Unregulated Business Operations:
Operating expenses for our wholesale unregulated business operations increased $4,948 million in 1998 from 1997. This reflects the increase in the volumes of energy commodities purchased at PG&E ET and operating costs associated with our newly acquired New England assets at USGen and the gas transportation assets at PG&E GTT.

Wholesale unregulated business operations operating expenses in 1997 increased $5,629 million from 1996, which reflects the increase in the volume of energy commodities purchased due to our 1997 acquisitions.

Retail Unregulated Business Operations:
Retail unregulated business operations operating expenses increased $280 million in 1998 as compared to 1997. This increase is primarily due to the expansion of our energy services business.

Retail unregulated business operations operating expenses totaled $190 million in 1997, the first year of operation.

Other Income, Net:
Other income, net was $64 million in 1998 as compared to $201 million in 1997. The decrease was primarily due to the $23 million loss on the sale of our Australian holdings, discussed above, and a $120 million gain recorded in 1997.

Other income, net increased by $188 million in 1997 as compared to 1996 primarily due to a $120 million gain realized on the sale of interests in International Generating Company, Ltd.

Interest Expense:
Interest expense increased $117 million in 1998 from 1997. This increase was primarily a result of increased interest costs for the Utility's rate reduction bonds and debt for the acquisition of the Texas and New England assets.

Interest expense in 1997 increased $33 million from 1996 primarily due to interest costs related to the Texas acquisitions.

Income Taxes:
Income taxes in 1998 increased $22 million from 1997. The overall effective tax rate increased 0.9 percent in 1998 largely due to accelerated book depreciation and amortization related to electric industry restructuring. These increases were partially offset by a lowered effective state tax rate resulting from our expanded business operations.

The effective tax rate decreased slightly in 1997 as compared to 1996, resulting in a $7 million decrease in 1997 taxes.

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

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. In 1998, the Utility was in compliance with its CPUC-authorized capital structure. PG&E Corporation and the Utility believe that the Utility will continue to meet this requirement in the future without affecting PG&E Corporation's ability to pay common stock dividends.

Liquidity and Financial Resources

Cash Flows from Operating Activities:
Net cash provided by PG&E Corporation's operating activities totaled $2.3 billion, $2.6 billion, and $2.6 billion in 1998, 1997, and 1996, respectively. Net cash provided by the Utility's operating activities totaled $2.6 billion, $1.8 billion, and $2.6 billion in 1998, 1997, and 1996, respectively.

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

During 1998, 1997, and 1996, we issued $63 million, $54 million, and $220 million of common stock, respectively, primarily through the Dividend Reinvestment Plan, the Stock Option Plan, and the Long-Term Incentive Plan. During 1997, we also issued $1.1 billion of common stock to acquire the natural gas assets in Texas. During 1998, 1997, and 1996, we paid dividends of $470 million, $524 million, and $844 million, respectively.

During 1998, 1997, and 1996, we repurchased $1,158 million, $804 million, and $455 million, respectively, of our common stock. In February 1999, PG&E Corporation used the remaining portion of an existing authorization to repurchase 16.6 million shares at a price of $30.25 per share.

In 1998, our unregulated business operations retired $75 million of long-term debt and retired the notes used in our acquisition of the Australian holdings. During 1997, our unregulated business operations issued $30 million and retired $109 million of long-term debt. Also in 1997, we assumed $780 million of long-term debt in connection with the acquisition of the natural gas assets in Texas. In 1996, we entered into additional loan agreements of $92 million to finance the acquisition of our energy holdings in Australia.

We maintain a number of credit facilities throughout our organization to support commercial paper programs, letters of credit, and other short term liquidity requirements. At PG&E Corporation, we maintain two $500 million revolving credit facilities, one of which expires in November 1999 and the other in 2002. The PG&E Corporation credit facilities are used to support the commerical paper program and other liquidity needs. The facility expiring in 1999 may be extended annually for additional one-year periods upon agreement between the lending institutions and us. There was $683 million of commercial paper outstanding at December 31, 1998.

In September 1998, USGen obtained $1,675 million in revolving credit facilities. Of these, $575 million is specifically related to the New England operations. Of the New England facility, $475 million was used to execute a sale leaseback transaction related to the newly acquired New England assets and subsequently cancelled. No amounts are outstanding under the New England facilities at December 31, 1998. USGen, itself, maintains two credit facilities of $550 million each. One agreement expires in August 1999 and the other in 2003. These facilities were used in the acquisition of the New England assets and for general corporate purposes. The total amount outstanding at December 31, 1998, backed by the facilities, was $540 million in eurodollar loans and $233 million in commercial paper. Of these loans, $550 million is classified as noncurrent in the consolidated balance sheet.

At December 31, 1998, PG&E GTT had $70 million of outstanding short-term bank borrowings related to two separate credit facilities. These lines are cancelable upon demand and bear interest at each respective bank's quoted money market rate. The borrowings are unsecured and unrestricted as to use.

PG&E GT NW maintains a $200 million revolving credit facility which expires in the year 2000. At December 31, 1998 and 1997, PG&E GT NW had outstanding commercial paper balances of $104 million and $80 million, respectively, supported by this revolving facility. These balances were classified as noncurrent obligations in the consolidated balance sheet.

Utility:

In 1998, the Utility repurchased $1.6 billion of its common stock from PG&E Corporation to maintain its authorized capital structure.

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

In 1997 and 1996, the Utility redeemed or repurchased $225 million and $1,113 million, respectively, of long-term debt to manage the overall balance of its capital structure. In 1997, the Utility replaced $360 million of fixed interest rate pollution control bonds with the same amount of variable interest rate pollution control bonds. In 1996, the Utility replaced $988 million of variable interest rate and fixed interest rate pollution control mortgage bonds and loan agreements with the same amount of variable interest rate pollution control loan agreements.

In 1998, the Utility redeemed its Series 7.44% preferred stock with a face value of $65 million and its Series 6⅞% preferred stock with a face value of $43 million. During 1997 and 1996, the Utility did not redeem or repurchase any of its preferred stock.

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

The Utility maintains a $1 billion revolving credit facility, which expires in 2002. The Utility may extend the facility annually for additional one-year periods upon agreement with the banks. This facility is used to support the Utility's commercial paper program and other liquidity requirements. At December 31, 1998, the Utility had $567 million of commercial paper and $101 million of bank notes outstanding. No amounts were outstanding at December 31, 1997.

Debt Obligations and Rate Reduction Bonds: The table below provides information about our debt obligations and rate reduction bonds at December 31, 1998:

Expected maturity date	1999	2000	2001	2002	2003	Thereafter	Total
(dollars in millions)							
Utility:							
Long-term debt							
Variable rate obligations	—	$200	$100	$ 738	$310	—	$1,348
Fixed rate obligations	$260	$266	$274	$ 382	$372	$2,802	$4,356
Average interest rate	6.2%	6.6%	8.0%	7.8%	6.3%	7.1%	7.1%
Rate reduction bonds	$290	$290	$290	$ 290	$290	$1,161	$2,611
Average interest rate	6.1%	6.2%	6.2%	6.3%	6.4%	6.4%	6.3%
Wholesale and Retail Unregulated Business Operations:							
Long-term debt							
Variable rate obligations	$ 7	$115	$ 12	$ 10	$560	$ 125	$ 829
Fixed rate obligations	$ 71	$117	$ 94	$ 126	$ 46	$ 773	$1,227
Average interest rate	10.4%	9.1%	9.1%	8.7%	9.9%	8.2%	8.6%

Cash Flows from Investing Activities: The primary uses of cash for investing activities are additions to property, plant, and equipment; unregulated investments in partnerships; and acquisitions. The Utility's estimated capital spending for 1999 is $1.7 billion. Utility capital expenditures are based on estimates prepared for the Utility's GRC, but exclude capital expenditures for divested fossil and geothermal power plants. These estimates may be reduced if the CPUC authorized base revenues are significantly lower than those requested by the Utility in its GRC filing.

In 1998, the Utility had proceeds of $501 million from the sale of three fossil-fueled generation plants. Also in 1998, PG&E Corporation sold its Australian energy holdings, for proceeds of approximately $126 million. In 1997, PG&E Corporation sold its interest in International Generating Company, Ltd., resulting in an after-tax gain of approximately $120 million.

Also in 1998, the Utility agreed to sell three other fossil-fueled generation plants and to sell its complex of geothermal generation facilities. The winning bids total $1,014 million. As of December 31, 1998, these four plants had a combined book value of $523 million and had a combined capacity of 4,289 MW. The sales are subject to the approval of regulatory agencies, including the CPUC, and conditioned upon the transfer of various permits and licenses. The Utility expects to complete the sale of these four plants in 1999.

Environmental Matters:

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

At December 31, 1998, the Utility expects to spend $296 million over the next 30 years for cleanup costs at identified sites. If other responsible parties fail to pay or expected outcomes change, then these costs may be as much as $487 million. Of the $296 million, the Utility has recovered $104 million (including remediation of generation plants divested, discussed above) and expects to recover another $160 million in future rates. The Utility mitigates its cost by seeking recovery from insurance carriers and other third parties. (See Note 15 of Notes to Consolidated Financial Statements.)

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility estimated costs using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for cleanup costs at additional sites or expected outcomes change.

Year 2000:
The Year 2000 issue exists because many computer programs use only two digits to refer to a year, and were developed without considering the impact of the upcoming change in the century. If PG&E Corporation's computer systems fail or function incorrectly due to not being made Year 2000 ready, they could directly and adversely affect our ability to generate or deliver our products and services or could otherwise affect revenues, safety, or reliability for such a period of time as to lead to unrecoverable consequences.

Our plan to address the Year 2000 issues focuses on mission-critical systems whose components are categorized as in-house software, vendor software, embedded systems, and computer hardware. The four phases of our plan to address these systems are inventory and assessment, remediation, testing, and certification. Certification occurs when mission-critical systems are formally determined to be Year 2000 ready.

Our Year 2000 project is generally proceeding on schedule. The following table indicates our Year 2000 progress as of January 11, 1999. The percentages in this table reflect approximations based on a standardized reporting system that combines subsidiary results to provide a consistent, company-wide view.

Year 2000 Readiness of Mission-Critical Items

	Remediation Complete	Testing Complete	Certification Complete
In-house software	94%	91%	11%
Vendor software	53%	26%	2%
Embedded systems	95%	91%	0%
Computer hardware	92%	60%	0%

Changes in company inventories, or issues uncovered in subsequent phases for an item previously reported as completed, may lead to downward adjustments in percentages from period to period. Also, the completion of these phases does not address external interdependencies that could affect the ability of the company to be Year 2000 ready. Even after systems are certified, we may continue various kinds of testing through the end of 1999.

Although 91 percent of remediation and testing of embedded systems has been completed, the remaining 9 percent in this area may require some of the more challenging work.

In addition to internal systems, we also depend upon external parties, including customers, suppliers, business partners, gas and electric system operators, government agencies, and financial institutions to support the functioning of our business. To the extent that any of these parties are considered mission-critical to our business and experience Year 2000 problems in their systems, our mission-critical business functions may be adversely affected. To deal with this vulnerability, we have another phased approach. The primary phases for dealing with external parties are: (1) inventory, (2) action planning, (3) risk assessment, and (4) contingency planning. We have completed our inventory and action planning phases for mission-critical external parties. We expect to complete the risk assessment by March 1999 and the contingency planning phase by July 1999.

Although we expect our efforts and those of our external parties to be largely successful, we recognize that with the complex interaction of today's computing and communications systems, we cannot be certain we will be completely successful. Therefore, contingency plans for Year 2000 readiness are being developed and tested throughout 1999 to address our external dependencies as well as any significant schedule delays of mission-critical system work, should they occur. These plans will take into account possible interruptions of power, computing, financial, and communications infrastructures. Due to the speculative nature of contingency planning, however, it is uncertain whether these plans will be sufficient to remove the risk of material impacts on our operations resulting from Year 2000 problems.

In 1997 and through December 1998, we spent approximately $108 million to assess and remediate Year 2000 problems. About $64 million of this cost was for software systems that we replaced for business purposes generally unrelated to addressing Year 2000 readiness, but whose schedule we advanced to meet Year 2000 requirements. The replacement costs for these accelerated systems were capitalized. Our estimate of future costs to address mission-critical Year 2000 issues is approximately $140 million. About $60 million of these remaining Year 2000 costs will be capitalized because they relate to the purchase and installation of systems and equipment for general business purposes and the remaining $80 million will be expensed.

Based on our current schedule for the completion of Year 2000 tasks, we expect to secure Year 2000 readiness of our mission-critical systems by the end of the third quarter of 1999. However, as our current schedule is partially dependent on the efforts of third parties, their delays may cause our schedule to change.

If we, or third parties with whom we have significant business relationships, fail to achieve Year 2000 readiness of mission-critical systems, there could be a material adverse impact on the Utility's and PG&E Corporation's financial position, results of operations, and cash flows.

Inflation:

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

Price Risk Management Activities:

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

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

PG&E Corporation utilizes historical data for calculating the price volatility of PG&E Corporation's positions and how likely the prices of those positions will move together. The model includes all derivative and commodity investments for its trading portfolio and only derivative commodity investments for its hedging portfolio (but not the related underlying hedged position). PG&E Corporation expresses value-at-risk as a dollar amount of the potential loss in the fair value of its portfolio based on a 95 percent confidence level using a one-day liquidation period. Therefore, there is a 5 percent probability that a portfolio will incur a loss in one day greater than its value-at-risk. The value-at-risk is aggregated for PG&E Corporation as a whole by correlating the daily returns of the portfolios for natural gas, natural gas liquids, and power for the previous 22 trading days. PG&E Corporation's daily value-at-risk for commodity price sensitive derivative instruments as of December 31, 1998, is $6.2 million for trading activities and $0.2 million for non-trading activities.

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

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, which is required to be adopted in years beginning after June 15, 1999. The Statement permits early adoption as of the beginning of any fiscal quarter. PG&E Corporation expects to adopt the new Statement no later than January 1, 2000. The Statement will require PG&E Corporation to recognize all derivatives, as defined in the Statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not effective hedges must be adjusted to fair value through income. If derivatives are effective hedges, depending on the nature of the hedges, changes in the fair value of derivatives either will be offset against the change in fair value of the hedged assets, liabilities, or firm commitments through earnings or will be recognized in other comprehensive income until the hedged items are recognized in earnings. PG&E Corporation is currently evaluating what the effect of SFAS No. 133 will be on the earnings and financial position of PG&E Corporation. PG&E Corporation uses the mark-to-market method of accounting for its commodity trading and price risk management activities.

In November 1998, the Emerging Issues Task Force of the Financial Accounting Standards Board released Issue 98-10, Accounting for Energy Trading and Risk Management Activities. This Issue states that all energy-related contracts entered into with the objective of generating profits on or from exposure to shifts or changes in market prices be marked to market with the gains and losses reflected in the income statement. The Task Force stipulates implementation for fiscal years beginning after December 15, 1998. PG&E Corporation does not believe that the effect of adoption of this standard on earnings or the financial position of PG&E Corporation will be material.

Legal Matters:

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

Statement of Consolidated Income

(in millions, except per share amounts) Year ended December 31,	1998	1997	1996
Operating Revenues			
Utility	$ 8,924	$ 9,495	$8,989
Energy commodities and services	11,018	5,905	621
Total operating revenues	19,942	15,400	9,610
Operating Expenses			
Cost of energy for utility	3,029	3,287	3,142
Cost of energy commodities and services	10,194	5,481	356
Operating and maintenance, net	3,103	3,052	2,994
Depreciation, amortization, and decommissioning	1,609	1,852	1,222
Total operating expenses	17,935	13,672	7,714
Operating Income	2,007	1,728	1,896
Interest expense, net	(782)	(665)	(632)
Other income, net	64	201	13
Income Before Income Taxes	1,289	1,264	1,277
Income taxes	570	548	555
Net Income	$ 719	$ 716	$ 722
Weighted Average Common Shares Outstanding	382	410	413
Earnings Per Common Share, Basic and Diluted	$ 1.88	$ 1.75	$ 1.75
Dividends Declared Per Common Share	$ 1.20	$ 1.20	$ 1.77

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

Consolidated Balance Sheet

(in millions) Balance at December 31,	1998	1997
Assets		
Current Assets		
Cash and cash equivalents	$ 286	$ 237
Short-term investments	55	1,160
Accounts receivable		
Customers, net	1,856	1,514
Regulatory balancing accounts	—	458
Energy marketing	507	830
Price risk management	1,416	500
Inventories and prepayments	835	626
Total current assets	4,955	5,325
Property, Plant, and Equipment		
Utility	23,996	23,764
Wholesale and retail unregulated business operations		
Electric generation	1,967	—
Gas transmission	3,347	3,415
Construction work in progress	407	492
Other	127	55
Total property, plant, and equipment (at original cost)	29,844	27,726
Accumulated depreciation and decommissioning	(12,026)	(11,617)
Net property, plant, and equipment	17,818	16,109
Other Noncurrent Assets		
Regulatory assets	6,347	6,900
Nuclear decommissioning funds	1,172	1,024
Other	2,942	1,757
Total noncurrent assets	10,461	9,681
Total Assets	$33,234	$31,115

Consolidated Balance Sheet

(in millions) Balance at December 31,	1998	1997
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 1,644	$ 103
Current portion of long-term debt	338	659
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	1,001	754
Other	443	466
Regulatory balancing accounts	79	—
Energy marketing	381	758
Accrued taxes	103	226
Price risk management	1,412	512
Other	1,064	893
Total current liabilities	6,755	4,661
Noncurrent Liabilities		
Long-term debt	7,422	7,659
Rate reduction bonds	2,321	2,611
Deferred income taxes	3,861	4,029
Deferred tax credits	283	339
Other	3,746	2,024
Total noncurrent liabilities	17,633	16,662
Preferred Stock of Subsidiaries	480	595
Utility Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures	300	300
Common Stockholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued and outstanding, 382,603,564 and 417,665,891	5,862	6,366
Reinvested earnings	2,204	2,531
Total common stockholders' equity	8,066	8,897
Commitments and Contingencies (Notes 1, 2, 3, 4, 5, 14, and 15)	—	—
Total Liabilities and Stockholders' Equity	$33,234	$31,115

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

Statement of Consolidated Cash Flows

(in millions) For the year ended December 31,	1998	1997	[illegible]6
Cash Flows From Operating Activities			
Net income	$ 719	$ 716	$ 722
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,609	1,852	1,222
Deferred income taxes and tax credits-net	(107)	(159)	(150)
Other deferred charges and noncurrent liabilities	18	121	116
Loss (gain) on sale of assets	23	(120)	—
Net effect of changes in operating assets and liabilities:			
Accounts receivable — trade	(342)	(242)	(70)
Regulatory balancing accounts receivable	537	126	302
Inventories and prepayments	(161)	(4)	32
Price risk management assets and liabilities, net	(16)	12	—
Accounts payable — trade	247	210	217
Accrued taxes	(123)	(54)	36
Other working capital	199	(85)	(6)
Other-net	(302)	245	160
Net cash provided by operating activities	2,301	2,618	2,581
Cash Flows From Investing Activities			
Capital expenditures	(1,619)	(1,822)	(1,230)
Acquisitions and investments in unregulated projects	(1,779)	(116)	(229)
Proceeds from sale of assets	1,106	146	—
Other-net	48	21	(120)
Net cash used by investing activities	(2,244)	(1,771)	(1,579)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	2,115	(587)	(115)
Long-term debt issued	—	386	1,088
Long-term debt matured, redeemed, or repurchased	(1,552)	(961)	(1,472)
Proceeds from issuance of rate reduction bonds	—	2,881	—
Preferred stock redeemed or repurchased	(108)	—	—
Common stock issued	63	54	220
Common stock repurchased	(1,158)	(804)	(455)
Dividends paid	(470)	(524)	(844)
Other-net	(3)	(39)	(14)
Net cash used by financing activities	(1,113)	406	(1,592)
Net Change in Cash and Cash Equivalents	(1,056)	1,253	(590)
Cash and Cash Equivalents at January 1	1,397	144	734
Cash and Cash Equivalents at December 31	$ 341	$ 1,397	$ 144
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 774	$ 624	$ 598
Income taxes	770	801	640

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

Statement of Consolidated Common Stock Equity

(dollars in millions)	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Total Common Stock Equity
Balance December 31, 1995	$2,070	$3,716	$2,813	$8,599
Net income			722	722
Common stock issued (9,290,102 shares)	47	173		220
Common stock repurchased (19,811,396 shares)	(99)	(182)	(174)	(455)
Cash dividends declared				
Common stock			(729)	(729)
Other		3	4	7
Balance December 31, 1996	2,018	3,710	2,636	8,364
Net income			716	716
Holding company formation	3,710	(3,710)		—
Common stock issued (2,302,544 shares)	54			54
Acquisitions (45,683,005 shares)	1,069			1,069
Common stock repurchased (33,823,950 shares)	(496)		(308)	(804)
Cash dividends declared				
Common stock			(485)	(485)
Other	11		(28)	(17)
Balance December 31, 1997	6,366	—	2,531	8,897
Net income			719	719
Common stock issued (2,028,303 shares)	63			63
Common stock repurchased (37,090,630 shares)	(565)		(593)	(1,158)
Cash dividends declared				
Common stock			(466)	(466)
Other	(2)		13	11
Balance December 31, 1998	$5,862	$ —	$2,204	$8,066

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

Statement of Consolidated Income

(in millions) Year ended December 31,	1998	1997	1996
Operating Revenues			
Electric utility	$7,191	$7,691	$7,160
Gas utility	1,733	1,804	1,829
Energy commodities and services	—	—	621
Total operating revenues	8,924	9,495	9,610
Operating Expenses			
Cost of electric energy	2,321	2,501	2,261
Cost of gas	708	786	881
Cost of energy commodities and services	—	—	356
Operating and maintenance, net	2,581	2,629	2,994
Depreciation, amortization, and decommissioning	1,438	1,748	1,222
Total operating expenses	7,048	7,664	7,714
Operating Income	1,876	1,831	1,896
Interest expense, net	(621)	(570)	(632)
Other income, net	103	116	46
Income Before Income Taxes	1,358	1,377	1,310
Income taxes	629	609	555
Net Income	729	768	755
Preferred dividend requirement	27	33	33
Income Available for Common Stock	$ 702	$ 735	$ 722

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

Consolidated Balance Sheet

(in millions) Balance at December 31,	1998	1997
Assets		
Current Assets		
Cash and cash equivalents	$ 73	$ 80
Short-term investments	17	1,143
Accounts receivable		
Customers, net	1,383	1,204
Regulatory balancing accounts	—	458
Related parties	14	459
Inventories		
Fuel oil and nuclear fuel	187	207
Gas stored underground	130	102
Materials and supplies	159	189
Prepayments	50	25
Total current assets	2,013	3,867
Property, Plant, and Equipment		
Electric	16,924	16,913
Gas	7,072	6,851
Construction work in progress	273	421
Total property, plant, and equipment (at original cost)	24,269	24,185
Accumulated depreciation and decommissioning	(11,397)	(11,134)
Net property, plant, and equipment	12,872	13,051
Other Noncurrent Assets		
Regulatory assets	6,288	6,846
Nuclear decommissioning funds	1,172	1,024
Other	605	359
Total noncurrent assets	8,065	8,229
Total Assets	$22,950	$25,147

Consolidated Balance Sheet

(in millions) Balance at December 31,	1998	1997
Liabilities and Equity		
Current Liabilities		
Short-term borrowings	$ 668	$ —
Current portion of long-term debt	260	580
Current portion of rate reduction bonds	290	290
Accounts payable		
Trade creditors	718	441
Related parties	60	134
Regulatory balancing accounts	79	—
Other	374	424
Accrued taxes	2	229
Deferred income taxes	3	149
Other	558	527
Total current liabilities	3,012	2,774
Noncurrent Liabilities		
Long-term debt	5,444	6,218
Rate reduction bonds	2,321	2,611
Deferred income taxes	3,060	3,304
Deferred tax credits	283	338
Other	2,045	1,810
Total noncurrent liabilities	13,153	14,281
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002–2009	137	137
Company Obligated Mandatorily Redeemable Preferred Securities of Trust Holding Solely Utility Subordinated Debentures		
7.90%, 12,000,000 shares, due 2025	300	300
Stockholders' Equity		
Preferred stock without mandatory redemption provisions		
Nonredeemable — 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable — 4.36% to 7.04%, outstanding 5,973,456 shares	142	257
Common stock, $5 par value, authorized 800,000,000 shares; issued and outstanding, 341,353,455 and 403,504,292	1,707	2,018
Additional paid in capital	2,094	2,564
Reinvested earnings	2,260	2,671
Total stockholders' equity	6,348	7,655
Commitments and Contingencies (Notes 1, 2, 3, 4, 5, 14, and 15)	—	—
Total Liabilities and Stockholders' Equity	$22,950	$25,147

The accompanying Notes to the Consolidat- inancial Statements are an integral part of this statement.

Statement of Consolidated Cash Flows

(in millions) For the year ended December 31,	1998	1997	1996
Cash Flows From Operating Activities			
Net income	$ 729	$ 768	$ 755
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization, and decommissioning	1,438	1,748	1,222
Deferred income taxes and tax credits-net	(257)	(182)	(150)
Other deferred charges and noncurrent liabilities	31	133	116
Net effect of changes in operating assets and liabilities:			
Accounts receivable	266	(582)	(70)
Regulatory balancing accounts receivable	537	126	302
Inventories and prepayments	(3)	12	32
Accounts payable — trade	203	(80)	217
Accrued taxes	(227)	(62)	36
Other working capital	(50)	(128)	(6)
Other-net	(39)	15	127
Net cash provided by operating activities	2,628	1,768	2,581
Cash Flows From Investing Activities			
Capital expenditures	(1,382)	(1,522)	(1,230)
Acquisitions and investments in unregulated projects	—	—	(229)
Proceeds from sale of generation assets	501	—	—
Other-net	22	(117)	(120)
Net cash used by investing activities	(859)	(1,639)	(1,579)
Cash Flows From Financing Activities			
Net borrowings (repayments) under credit facilities	668	(681)	(115)
Long-term debt issued	—	355	1,088
Long-term debt matured, redeemed, or repurchased	(1,413)	(852)	(1,472)
Proceeds from issuance of rate reduction bonds	—	2,881	—
Preferred stock redeemed	(108)	—	—
Common stock repurchased	(1,600)	—	—
Dividends paid	(444)	(739)	(844)
Other-net	(5)	(14)	(249)
Net cash used by financing activities	(2,902)	950	(1,592)
Net Change in Cash and Cash Equivalents	(1,133)	1,079	(590)
Cash and Cash Equivalents at January 1	1,223	144	734
Cash and Cash Equivalents at December 31	$ 90	$ 1,223	$ 144
Supplemental disclosures of cash flow information			
Cash paid for:			
Interest (net of amounts capitalized)	$ 600	$ 547	$ 598
Income taxes	1,115	841	640

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

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

(dollars in millions)	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Total Common Stock Equity	Preferred Stock Without Mandatory Redemption Provisions	Preferred Stock With Mandatory Redemption Provisions	Company Obligated Mandatorily Redeemable Preferred Securities
Balance December 31, 1995	$2,070	$3,716	$2,813	$8,599	$402	$137	$300
Net income			755	755			
Common stock issued							
(9,290,102 shares)	47	173		220			
Common stock repurchased							
(19,811,396 shares)	(99)	(182)	(174)	(455)			
Cash dividends declared							
Preferred stock			(33)	(33)			
Common stock			(729)	(729)			
Other		3	4	7			
Balance December 31, 1996	2,018	3,710	2,636	8,364	402	137	300
Net income			768	768			
Holding company formation		(1,146)		(1,146)			
Cash dividends declared							
Preferred stock			(33)	(33)			
Common stock			(699)	(699)			
Other			(1)	(1)			
Balance December 31, 1997	2,018	2,564	2,671	7,253	402	137	300
Net income			729	729			
Common stock repurchased							
(62,150,837 shares)	(311)	(481)	(808)	(1,600)			
Preferred stock redeemed							
(4,323,948 shares)			(3)	(3)	(105)		
Cash dividends declared							
Preferred stock			(28)	(28)			
Common stock			(300)	(300)			
Other		11	(1)	10	(10)		
Balance December 31, 1998	$1,707	$2,094	$2,260	$6,061	$287	$137	$300

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

Note 1: General

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

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's consolidated financial statements include the accounts of PG&E Corporation, the Utility, and PG&E Corporation's other wholly owned subsidiaries. The Utility's consolidated financial statements include its accounts as well as those of its wholly owned subsidiaries. PG&E Corporation and the Utility have identical 1996 consolidated financial statements because they represent the accounts of the Utility as predecessor of PG&E Corporation. All significant intercompany transactions have been eliminated from the consolidated financial statements. Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the 1998 presentation.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets, and liabilities and the disclosure of contingencies. Actual results could differ from these estimates.

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

Operations: PG&E Corporation is an energy-based holding company headquartered in San Francisco, California. PG&E Corporation's businesses provide energy services throughout North America. PG&E Corporation's Northern and Central California energy utility subsidiary, Pacific Gas and Electric Company, provides natural gas and electric service to one of every 20 Americans. PG&E Corporation's four unregulated businesses provide a wide range of energy products and services through its wholesale and retail unregulated business operations.

PG&E Corporation's wholesale unregulated business operations consist of U.S. Generating Company (USGen) which develops, builds, operates, owns, and manages power generation facilities that serve wholesale and industrial customers; PG&E Gas Transmission (PG&E GT) which operates approximately 9,000 miles of natural gas pipelines, natural gas storage facilities, and natural gas processing plants in the Pacific Northwest (PG&E GT NW) and Texas (PG&E GTT); and PG&E Energy Trading (PG&E ET) which purchases and resells energy commodities and related financial instruments in major North American markets, serving PG&E Corporation's other unregulated businesses, unaffiliated utilities, and large end-use customers.

PG&E Corporation's retail unregulated business operations consist of PG&E Energy Services (PG&E ES) which provides competitively priced electricity, natural gas, and related services to lower overall energy costs for industrial, commercial, and institutional customers.

Regulation and Statements of Financial Accounting Standards (SFAS) No. 71: The Utility is regulated by the CPUC, the FERC, and the Nuclear Regulatory Commission (NRC) among others. The gas transmission business in the Pacific Northwest is regulated by the FERC. The gas transmission business in Texas is regulated by the Texas Railroad Commission.

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

Regulatory assets and liabilities are comprised of the following:

December 31, (in millions)	1998	1997
Utility:		
Generation-related transition costs[1]	$5,355	$5,964
Unamortized loss, net of gain, on reacquired debt	289	283
Regulatory assets for deferred income tax	293	253
Other (net)	351	346
Total Utility	$6,288	$6,846
Wholesale	59	54
Regulatory assets	$6,347	$6,900
Regulatory liabilities	$ 526	$ 477

[1] See Note 2 of Notes to Consolidated Financial Statements, for further discussion.

Regulatory assets and liabilities are amortized over the period that the costs are reflected in regulated revenues. The majority of the Utility's regulatory assets are included in generation-related transition costs. The Utility is amortizing its eligible transition costs, including generation-related regulatory assets, over the transition period in conjunction with the available competitive transition charge (CTC) revenues. During 1998, regulatory assets related to electric utility restructuring decreased by $609 million. This decrease reflects the recovery of eligible transition costs of $486 million through accelerated amortization and $123 million through the gain on the sale of generating plants.

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

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

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

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

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

For regulatory reasons, the Utility manages price risk independently from the activities in PG&E Corporation's unregulated business. In the first quarter of 1998, the CPUC granted approval for the Utility to use financial instruments to manage price volatility of gas purchased for the Utility's electric generation portfolio. The approval limits the Utility's outstanding financial instruments to $200 million, with downward adjustments occurring as the Utility divests its fossil-fueled generation plants. (See Utility Generation Divestiture, below.) Authority to use these risk management instruments ceases upon the full divestiture of fossil-fueled generation plants or at the end of the current electric rate freeze (see Rate Freeze and Rate Reduction, below), whichever comes first.

In the second quarter of 1998, the CPUC granted conditional authority to the Utility to use natural gas-based financial instruments to manage the impact of natural gas prices on the cost of electricity purchased pursuant to existing power-purchase contracts. Under the authority granted in the CPUC decision, no natural gas-based financial instruments shall have an expiration date later than December 31, 2001. Further, if the rate freeze ends before December 31, 2001, the Utility shall net any outstanding financial instrument contracts through equal and opposite contracts, within a reasonable amount of time. Also during the fourth quarter, the CPUC granted conditional authority to the Utility to use natural gas-based financial instruments to manage price and revenue risks associated with its natural gas transmission and storage assets.

Property, Plant, and Equipment: Plant additions and replacements are capitalized. The capitalized costs include labor, materials, construction overhead, and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions. The Utility recovers AFUDC in rates through depreciation expense over the useful life of the related asset.

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

Property, plant, and equipment is depreciated using a straight-line remaining-life method. PG&E Corporation's composite depreciation rates were 4.11 percent, 3.70 percent, and 3.37 percent for the years ended December 31, 1998, 1997, and 1996, respectively. The Utility's composite depreciation rates were 4.15 percent, 3.52 percent, and 3.37 percent for the years ended December 31, 1998, 1997, and 1996, respectively.

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

Inventories: Inventories include material and supplies, gas stored underground, nuclear fuel, and fuel oil. Materials and supplies and gas stored underground are valued at average cost. Stored nuclear fuel inventory is stated at lower of average cost or market. Nuclear fuel in the reactor is amortized based on the amount of energy output. Fuel oil is valued by the last-in-first-out method.

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

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

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

Related Party Agreements: In accordance with various agreements, the Utility and other subsidiaries provide and receive various services from their parent, PG&E Corporation. Services include the Utility's provision of general and administrative services. The Utility and other subsidiaries receive general and administrative services and financing from PG&E Corporation. Corporate costs, such as administrative costs, interest, and income taxes, are allocated to subsidiaries using a variety of factors including their share of employees, operating expenses, assets, and other cost causal methods. Also, the Utility purchases gas transmission services from PG&E GT NW.

Note 2: California Electric Industry Restructuring

In 1998, California became one of the first states in the country to implement an electric industry restructuring plan. California electric industry restructuring has two major impacts on the financial statements. The two major components are the competitive market framework and the electric transition plan, which are discussed below.

Competitive Market Framework: To create a competitive generation market, a Power Exchange (PX) and an Independent System Operator (ISO) began operating in 1998. The Utility is required to sell to the PX all of the electricity generated by its power plants and electricity acquired under contractual agreements with unregulated generators. Also, the Utility is required to buy from the PX all electricity needed to provide service to retail customers that continue to choose the Utility as their electricity supplier. The ISO schedules delivery of electricity for all market participants to the transmission system. The Utility continues to own and maintain a portion of the transmission system, but the ISO controls the operation of the system.

For the year ended December 31, 1998, the cost of energy for the Utility, reflected on the Statement of Consolidated Income, is comprised of the cost of PX purchases, ancillary services (standby power and miscellaneous services) purchased from the ISO, cost of transmission, and the cost of Utility generation, net of sales to the PX as follows:

For the year ended December 31,	1998
(in millions)	
Cost of fuel for electric generation	$2,030
Cost of purchases from the PX	723
Net cost of ancillary services	406
Proceeds from sales to the PX	(838)
Cost of electric energy	$2,321

The Utility's cost of energy is recovered from retail customers under the terms of the restructuring plan.

California Transition Plan: Market-based revenues determined by the market through sales to the PX may not be sufficient to recover (that is, to collect from customers) all of the Utility's generation costs. To allow California investor-owned utilities the opportunity to recover their transition costs (generation costs that would not be recovered through market-based revenues) and to ensure a smooth transition to a competitive market, the California legislature developed a transition plan in the form of state legislation that was passed in 1996. The transition plan will remain in effect until the earlier of December 31, 2001, or when the Utility has recovered its authorized transition costs as determined by the CPUC, with provisions that certain transition costs can be recovered after the transition period. At the conclusion of the transition period, the Utility will be at risk to recover any of its remaining generation costs through market-based revenues. The transition plan contains three principal elements consisting of the determination of: (1) an electric rate freeze and rate reduction, (2) the recovery of transition costs, and (3) divestiture of utility-owned generation facilities. Each element is discussed below.

• Rate Freeze and Rate Reduction:
The first element of the transition plan is an electric rate freeze and an electric rate reduction. In 1997 and 1998, the Utility held rates for its larger customers at 1996 levels, and it will hold their rates at that level until the end of the transition period. On January 1, 1998, the Utility reduced electric rates for its residential and small commercial customers by 10 percent from 1996 levels, and it will hold their rates at that level until the end of the transition period. Collectively, these actions are called a rate freeze.

To pay for the 10 percent rate reduction, the Utility refinanced $2.9 billion of its transition costs with the proceeds of rate reduction bonds. (See Note 9.) The bonds allow for the rate reduction by lowering the carrying cost on a portion of the transition costs and by deferring recovery of a portion of these transition costs until after the transition period.

The frozen rates include a component for transition cost recovery. Transition costs are being recovered from all Utility distribution customers through a nonbypassable charge regardless of the customer's choice of electricity supplier. As the customer charge for transition costs is nonbypassable, the Utility does not believe that the availability of choice to its customers will have a material impact on its ability to recover transition costs.

Revenues from frozen electric rates provide for the recovery of authorized Utility costs, including transmission and distribution service, public purpose programs, nuclear decommissioning, and rate reduction bond debt service. To the extent the revenues from frozen rates exceed authorized Utility costs, the remaining revenues constitute the CTC which recovers the transition costs. These CTC revenues are subject to seasonal fluctuations in the Utility's sales volumes and certain other factors.

• Transition Cost Recovery:
Transition costs consist of: (1) above-market sunk costs (sunk costs are costs associated with Utility-owned generation assets that are fixed and unavoidable and currently included in the Utility customers' electric rates) and future costs, such as costs related to plant removal of Utility-owned generation facilities, (2) costs associated with the Utility's long-term contracts to purchase power at above-market prices from qualifying facilities and other power suppliers, and (3) generation-related regulatory assets and obligations. (In general, regulatory assets are expenses deferred in the current or prior periods to be included in rates in subsequent periods.)

Above-market sunk costs result when the book value of a facility is in excess of its market value. Conversely, below-market sunk costs result when the market value of a facility is in excess of its book value. The total amount of generation facility costs to be included as transition costs will be based on the aggregate of above-market and below-market values. The above-market portion of these costs is eligible for recovery as a transition cost. The below-market portion of these costs will reduce other unrecovered transition costs. A valuation of a Utility-owned generation facility where the market value exceeds the book value could result in a material charge to Utility earnings if the valuation of the facility is determined based upon any method other than a sale of the facility to a third party. This is because any excess of market value over book value would be used to reduce other transition costs.

The Utility will not be able to determine the exact amount of above-market non-nuclear sunk costs that will be recoverable as transition costs until a market valuation process (appraisal, spin, sale, or other valuation method) is completed for each of its generation facilities. Several of these valuations occurred in 1997 and 1998, when the Utility agreed to sell seven of its electric plants. The market value of these facilities determined by these sales exceeded the book value and will therefore reduce the amount of transition costs to be recovered. In addition, in December 1998, the Utility requested that the CPUC allow it to hire appraisers to set the value of its hydroelectric generation system. (See Generation Divestiture below.) The remainder of the valuation process is expected to be completed by December 31, 2001. Nuclear sunk costs were separately determined through a CPUC proceeding and were subject to a final verification audit. This audit was completed in August 1998, the results of which are currently under review.

The Utility has long-term contracts to purchase electric power at above-market prices. To the extent that individual contract prices are above market price, the Utility is collecting the difference between the contract price and the market price from customers, as a transition cost, over the term of the contract. The contracts expire at various dates through 2028. The total amount of the above-market costs under long-term contracts will be based on several variables, including the capacity factors of the related generating facilities and future market prices for electricity. During 1998, the average price paid per kilowatt hour (kWh) under the Utility's long-term contracts for electric power was 7.4 cents per kWh. The average cost of electric energy for energy purchased at market rates from the PX (a measure of market prices) for the period from April 1, 1998, to December 31, 1998, was 3.2 cents per kWh.

Generation-related regulatory assets and obligations (net generation-related regulatory assets) are included as transition costs. These net regulatory assets consist of those created prior to the transition period and those created during the transition period. In 1998, the staff of the Securities and Exchange Commission (SEC) issued interpretive guidance related to assets which are being transitioned to a deregulated environment. The guidance states that an impairment analysis should be performed for such assets and that the impairment analysis should exclude transition cost revenues. Following this guidance, the Utility determined that \$3.9 billion of its generation assets were impaired. The Utility has determined that certain of its generation facilities are considered impaired under the SEC interpretive guidance. Because the Utility expects to recover the impaired assets as a transition cost, it recorded a regulatory asset for the impaired amounts as required. As a result, in 1998, \$3.9 billion was reclassified from property, plant, and equipment to regulatory assets on the Utility's balance sheet. Prior year amounts were also reclassified. The Utility's generation-related net regulatory assets total \$5.4 billion at December 31, 1998.

Under the transition plan, most transition costs can be recovered until December 31, 2001. This recovery period is significantly shorter than the recovery period of the generation assets prior to restructuring and is referred to as accelerated recovery. Accordingly, the Utility is amortizing its transition costs, including most generation-related regulatory assets over the transition period. The CPUC believes that the transition plan reduces risks associated with recovery of all the Utility's generation assets, including the Diablo Canyon Nuclear Power Plant (Diablo Canyon) and the hydroelectric facilities. As a result, during the transition period, the Utility is receiving a reduced return on common equity for all of its generation assets, including those generation assets reclassified to regulatory assets. In 1998, the reduced return on common equity was 6.77 percent as compared to an authorized return on common equity of 11.20 percent. The reduced return on common equity, related to generation assets, will be in effect throughout the transition period.

Certain transition costs can be included in a non-bypassable charge to distribution customers after the transition period. These costs include: (1) certain employee-related transition costs, (2) above-market payments under existing long-term contracts to purchase power, discussed above, and (3) unrecovered electric industry restructuring implementation costs. In addition, transition costs financed by the issuance of rate reduction bonds are expected to be recovered over the term of the bonds. Further, the Utility's nuclear decommissioning costs are being recovered through a CPUC-authorized charge, which will extend until sufficient funds exist to decommission our nuclear facility. During the rate freeze, this charge and the rate reduction bond debt service will not increase the Utility customers' electric rates. Excluding these exceptions, the Utility will write-off any transition costs not recovered during the transition period.

Under the terms of the transition plan, revenues provided for the recovery of most non-nuclear transition costs are based upon the acceleration of such costs within the transition period. For nuclear transition costs, revenues provided for transition cost recovery are based on: (1) an established incremental cost incentive price per kWh generated by Diablo Canyon to recover certain ongoing costs and capital additions, and (2) the accelerated recovery of the investment in Diablo Canyon from a period ending in 2016 to a five-year period ending December 31, 2001.

The Utility is amortizing its eligible transition cost, including generation-related regulatory assets, over the transition period in conjunction with available CTC revenues. Effective January 1, 1998, the Utility started collecting these eligible transition costs through the nonbypassable CTC. During 1998, regulatory assets related to electric utility restructuring decreased by $609 million. This decrease reflects the recovery of eligible transition costs of $486 million through accelerated amortization and $123 million through the gain on the sale of generating plants.

During the transition period, the CPUC will review the Utility's compliance with the accounting methods used by the Utility to recover transition costs and the amount of transition costs requested for recovery. The CPUC is currently reviewing non-nuclear transition costs amortized during the first six months of 1998. The Utility expects the CPUC to issue a decision regarding this review in the second half of 1999. Transition costs that are disallowed by the CPUC for collection from the Utility customers will be written off.

In addition, in August 1998, an independent accounting firm retained by the CPUC completed its financial verification audit of the Utility's Diablo Canyon plant accounts at December 31, 1996. The audit resulted in the issuance of an unqualified opinion. The audit verified that Diablo Canyon sunk costs at December 31, 1996, were $3.3 billion of the total $7.1 billion construction costs. (Sunk costs are costs associated with Utility-owned generating facilities that are fixed and unavoidable and currently included in the Utility customers' electric rates.) The independent accounting firm also issued an agreed-upon special procedures report, requested by the CPUC, which questioned $200 million of the $3.3 billion sunk costs. The CPUC will review any proposed adjustments to Diablo Canyon's recoverable costs, which resulted from the report. At this time, the Utility cannot predict what actions, if any, the CPUC may take regarding the audit report.

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

Also in 1998, the Utility agreed to sell three other fossil-fueled generation plants and its complex of geothermal generation facilities. The winning bids total $1,014 million. As of December 31, 1998, these four plants had a combined book value of $523 million and had a combined capacity of 4,289 MW. The sales are subject to the approval of regulatory agencies, including the CPUC, and conditioned upon the transfer of various permits and licenses. The Utility expects to complete the sale of these four plants in 1999.

The Utility will retain a liability for required environmental remediation related to all of its fossil-fueled generation and geothermal plants of any pre-closing soil or groundwater contamination at the plants it has or will sell. The Utility records its estimated liability for the retained environmental remediation obligation as part of the determination of the gain or loss on the sale of each plant.

Any net gains from the sale of the Utility-owned generation plants will be used to offset other transition costs. As a result, PG&E Corporation does not believe sales of any generation facilities to a third party will have a material impact on its results of operations.

The Utility is currently evaluating its options related to its remaining non-nuclear generation facilities, primarily the hydroelectric generation system. In May 1998, the Utility notified the CPUC that it does not plan to retain the hydroelectric generation assets as part of the Utility. In December 1998, the Utility filed with the CPUC its proposed appraisal process for valuing generation assets, primarily the hydroelectric facilities. The Utility expects to receive a response to this request in 1999.

At December 31, 1998, the book value of the Utility's net investment in hydroelectric generation assets was $1.4 billion. If the Utility decides to dispose of the hydroelectric generation assets by any method other than a sale of the assets to a third party, a material charge could result to the extent that the market value of the assets exceeds their book value. The market value of the hydroelectric assets is expected to exceed their book value by a material amount.

Financial Impact of Transition Plan: The Utility's ability to continue recovering its transition costs will be dependent on several factors, including: (1) the continued application of the regulatory framework established by the CPUC and state legislation, (2) the amount of transition costs ultimately approved for recovery by the CPUC, (3) the market value of the remaining Utility-owned generation facilities, (4) future Utility sales levels, (5) future Utility fuel and operating costs, (6) the extent to which the Utility's authorized revenues to recover distribution costs are increased or decreased, and (7) the market price of electricity. Given the current evaluation of these factors, PG&E Corporation believes that the Utility will recover its transition costs under the terms of the approved transition plan. However, a change in one or more of these factors could affect the probability of recovery of transition costs and result in a material charge.

Note 3: Price Risk Management and Financial Instruments

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

Natural Gas and Electricity Contracts	Purchase (Long)	Sale (Short)	Maximum Term in Years
(billions of MMBtu equivalents[a])			
Non-Hedging Activities			
Swaps	6.12	5.94	8
Options	1.39	1.18	5
Futures	0.44	0.46	4
Forward Contracts	3.68	3.53	5

[a] One MMBtu is equal to one million British thermal units. PG&E Corporation's electric power contracts, measured in megawatts, were converted to MMBtu equivalents using a conversion factor of 10 MMBtu's per 1 megawatt-hour.

Natural Gas Liquids Contracts	Purchase (Long)	Sale (Short)	Maximum Term in Years
(millions of barrels)			
Non-Hedging Activities			
Swaps	15.13	20.96	2
Options	19.24	17.69	1
Futures	24.16	25.18	1
Forward Contracts	5.01	5.[illegible]9	2

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

The following table discloses the estimated fair values of price risk management assets and liabilities as of December 31, 1998. PG&E Corporation's net gains and losses on swaps, options, futures, and forward contracts held during the year for non-hedging purposes were $69 million, $(49) million, $(63) million, and $101 million, respectively. The ending and average fair values and associated carrying amounts of derivative contracts used for hedging purposes are not material as of December 31, 1998.

	Average Fair Value	Ending Fair Value
(in millions)		
Assets		
Non-Hedging Activities		
Swaps	$ 494	$ 947
Options	121	154
Futures	115	150
Forward Contracts	342	499
Total	$1,072	$1,750
Noncurrent portion		334
Current portion		$1,416

	Average Fair Value	Ending Fair Value
(in millions)		
Liabilities		
Non-Hedging Activities		
Swaps	$ 476	$ 908
Options	147	201
Futures	111	186
Forward Contracts	282	398
Total	$1,016	$1,693
Noncurrent portion		281
Current portion		$1,412

The impact of price risk management assets and liabilities on PG&E Corporation's results of operations for fiscal 1997 was immaterial.

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

Generally, exchange-traded futures contracts require deposit of margin cash, the amount of which is subject to change based on market movement and in accordance with exchange rules. Margin cash requirements for over-the-counter financial instruments are specified by the particular instrument and often do not require margin cash and are settled monthly. Both exchange-traded and over-the-counter options contracts require payment/receipt of an option premium at the inception of the contract. Margin cash for commodities futures and cash on deposit with counterparties was immaterial at December 31, 1998.

Note 4: Concentrations of Market and Credit Risk

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

Credit Risk: The use of financial instruments to manage the risks associated with changes in energy commodity prices creates exposure resulting from the possibility of nonperformance by counterparties pursuant to the terms of their contractual obligation. The counterparties in PG&E Corporation's portfolio consist primarily of investor owned and municipal utilities, energy trading companies, financial institutions, and oil and gas production companies. PG&E Corporation minimizes credit risk by dealing primarily with creditworthy counterparties in accordance with established credit approval practices and limits. PG&E Corporation routinely assesses the financial strength of its counterparties and may require letters of credit or parental guarantees when the financial strength of a counterparty is not considered sufficient. PG&E Corporation has experienced no material losses due to the nonperformance of counterparties in 1998. The credit exposure of the five largest counterparties comprised approximately $127 million of the total credit exposure associated with financial instruments used to manage price risk. Counterparties considered to be investment grade or higher comprise 71 percent of the total credit exposure.

Note 5: Acquisitions and Sales

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

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

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

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

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

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

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

Note 6: Common Stock

PG&E Corporation: PG&E Corporation has authorized 800 million shares of no-par common stock of which 382,60[illegible],[illegible]4 and 417,665,891 shares were issued and outstanding as of December 31, 1998 and 1997, respectively.

As of December 31, 1997, the Board of Directors had authorized the repurchase of up to $1.7 billion of PG&E Corporation's common stock on the open market or in negotiated transactions. As part of this authorization, in January 1998, PG&E Corporation repurchased in a specific transaction 37 million shares of common stock. As of December 31, 1998, approximately $570 million remains available under this repurchase authorization. In February 1999, PG&E Corporation used this remaining authorization to purchase 16.6 million shares at a price of $30.25 per share. In connection with this transaction, PG&E Corporation has entered into a forward contract with an investment institution. PG&E Corporation will retain the risk of increases and the benefit of decreases in the price of the common shares purchased through the forward contract. This obligation will not be terminated until the investment institution has replaced the shares sold to PG&E Corporation through purchases on the open market or through privately negotiated transactions. The contract is anticipated to expire by year-end.

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

The Utility has authorized 800 million shares of $5 par value common stock of which 341,353,455 and 403,504,292 shares are issued and outstanding at December 31, 1998 and 1997, respectively.

The CPUC requires the Utility to maintain its CPUC-authorized capital structure, potentially limiting the amount of dividends the Utility may pay PG&E Corporation. In 1998, the Utility was in compliance with its CPUC-authorized capital structure.

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

Preferred Stock: The Utility has authorized 75,000,000 shares of $25 par value preferred stock which may be issued as redeemable or nonredeemable preferred stock. At December 31, 1998 and 1997, the Utility has issued and outstanding 5,784,825 shares of nonredeemable preferred stock.

At December 31, 1998 and 1997, the Utility has issued and outstanding 5,973,456 and 10,297,404 shares of redeemable preferred stock, respectively. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. Annual dividends and redemption prices per share at December 31, 1998, range from $1.09 to $1.76 and from $25.00 to $27.25, respectively. In 1998, the Utility redeemed its Series 7.44% preferred stock with a face value of $65 million. Also in 1998, the Utility redeemed its Series 6⅞% preferred stock with a face value of $43 million. During 1997 and 1996, the Utility did not redeem or repurchase any of its preferred stock.

The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57% series and 2.5 million shares of the 6.30% series at December 31, 1998. The 6.57% series and 6.30% series may be redeemed at the Utility's option beginning in 2002 and 2004, respectively, at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of stock outstanding.

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

Dividends on all preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. The estimated fair value of the Utility's preferred stock with mandatory redemption provisions at December 31, 1998 and 1997, was $143 million and $146 million, respectively, based on quoted market prices.

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

The Utility's guarantee of the QUIPS, considered together with the other obligations of the Utility with respect to the QUIPS, constitutes a full and unconditional guarantee by the Utility of the Trust's contractual obligations under the QUIPS issued by the Trust.

The subordinated debentures may be redeemed at the Utility's option beginning in 2000 at par value plus accrued interest through the redemption date. The proceeds of any redemption will be used by the Trust to redeem QUIPS in accordance with their terms.

Upon liquidation or dissolution of the Utility, holders of these QUIPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends thereon to the date of payment. The estimated fair value of the Utility's QUIPS at December 31, 1998 and 1997, was $303 million and $304 million, respectively, based on quoted market prices.

Note 8: Long-Term Debt

Long-term debt at December 31, 1998 and 1997, consisted of the following:

December 31, (in millions)		1998	1997
Utility long-term debt			
First and refunding mortgage bonds			
Maturity	Interest rates		
1999–2002	5.500% to 8.75%	$ 682	$1,241
2003–2007	5.875% to 6.250%	902	974
2008–2020	6.35% to 8.02%	160	160
2021–2026	5.85% to 8.80%	2,117	2,498
Principal amounts outstanding		3,861	4,873
Unamortized discount net of premium		(32)	(42)
Total mortgage bonds		3,829	4,831
Pollution control loan agreements, variable rates, due 2010–2026		1,348	1,348
Unsecured medium-term notes, 5.37% to 8.45%, due 1999-2014		498	587
Other Utility long-term debt		29	32
Total Utility long-term debt		5,704	6,798
Current portion of long-term debt		260	580
Total Utility long-term debt, net of current portion		5,444	6,218
Long-term debt of wholesale and retail unregulated business operations			
First mortgage notes			
10.02% to 11.50%, due 1999-2009		370	409
Senior notes			
10.58%, due 1999-2000		69	105
7.10%, due 2005		250	250
Medium term notes			
6.61% to 9.29%, due 2000-2012		298	298
Senior debentures			
7.80%, due 2025		148	148
Amounts outstanding under credit facilities (See Note 10)		654	80
Other long-term debt		267	230
Total wholesale and retail unregulated business operations long-term debt		2,056	1,520
Current portion of long-term debt		78	79
Long-term debt, net of current portion		1,978	1,441
Total long-term debt		$7,422	$7,659

Utility:

• First and Refunding Mortgage Bonds:

First and refunding mortgage bonds are issued in series and bear annual interest rates ranging from 5.50 percent to 8.80 percent. All real properties and substantially all personal properties of the Utility are subject to the lien of the bonds, and the Utility is required to make semi-annual sinking fund payments for the retirement of the bonds. Additional bonds may be issued subject to CPUC approval, up to a maximum total amount outstanding of $10 billion assuming compliance with indenture covenants for earnings coverage and available property balances as security.

The Utility redeemed or repurchased $501 million and $167 million of the bonds in 1998 and 1997, respectively, with interest rates ranging from 6.25 percent to 8.80 percent. These bonds were to mature from 2002 to 2026.

Included in the total of outstanding bonds at December 31, 1998 and 1997, are $345 million of bonds held in trust for the California Pollution Control Financing Authority (CPCFA) with interest rates ranging from 5.85 percent to 6.625 percent and maturity dates ranging from 2009 to 2023. In addition to these bonds, the Utility holds long-term pollution control loan agreements with the CPCFA as described below.

• Pollution Control Loan Agreements:
Pollution control loan agreements from the CPCFA totaled $1,348 million at December 31, 1998 and 1997. Interest rates on the loans vary with average annual interest rates. For 1998 the interest rates ranged from 2.56 percent to 3.68 percent. These loans are subject to redemption by the holder under certain circumstances. These loans are primarily secured by irrevocable letters of credit which mature 2000 through 2003.

Wholesale and Retail Unregulated Business Operations: Long-term debt of wholesale and retail unregulated business operations consists of first mortgage bonds and other secured and unsecured obligations.

The first mortgage notes are comprised of three series due serially from 1999 to 2009, and are secured by mortgages and security interests in the natural gas transmission and natural gas processing facilities and other real and personal property of PG&E GTT. The mortgage indenture requires semi-annual payments with one-half of each interest payment and one-fourth of each annual principal payment escrowed quarterly in advance. The mortgage indenture also contains covenants which restrict the ability of PG&E GTT to incur additional indebtedness and precludes cash distributions if certain cash flow coverages are not met.

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

Repayment Schedule: At December 31, 1998, PG&E Corporation's combined aggregate amounts of maturing long-term debt and sinking fund requirements, for the years 1999 through 2003, are $338 million, $698 million, $480 million, $1,256 million and $1,288 million, respectively. The Utility's share of those maturities and sinking fund requirements is $260 million, $466 million, $374 million, $1,120 million and $682 million, respectively.

Fair Value: The estimated fair value of PG&E Corporation's total long-term debt at December 31, 1998 and 1997, was $8.1 billion and $8.3 billion, respectively. The estimated fair value of the Utility's total long-term debt at December 31, 1998 and 1997, was $6.0 billion and $7.0 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 (for example, the present value of future cash flows).

Note 9: Rate Reduction Bonds

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

The rate reduction bonds have maturities ranging from ten months to ten years, and bear interest at rates ranging from 6.01 percent to 6.48 percent. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

At December 31, 1998, $2.6 billion of rate reduction bonds were outstanding. The combined expected principal payments on the rate reduction bonds for the years 1999 through 2003 are $290 million for each year.

The estimated fair value of the rate reduction bonds was $2.6 billion at December 31, 1998. The estimated fair value of the bonds was determined based on quoted market prices.

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

Note 10: Credit Facilities

PG&E Corporation: At December 31, 1998 and 1997, PG&E Corporation had borrowed $2,298 million and $183 million, respectively, under various credit facilities discussed below. $654 million and $80 million of these borrowings December 31, 1998 and 1997, respectively are classified as long-term debt. (See Note 8.) The weighted average interest rate on the short-term borrowings was 5.6 percent and 6.9 percent for 1998 and 1997, respectively. The carrying amount of short-term borrowings approximates fair value.

PG&E Corporation maintains two $500 million revolving credit facilities. One expires in November 1999 and the other in 2002. The facility expiring in November 1999 may be extended annually for additional one-year periods upon agreement between PG&E Corporation and the lending institutions. These credit facilities are used to support PG&E Corporation's commercial paper program and other liquidity needs. At December 31, 1998, PG&E Corporation had $683 million of commercial paper outstanding supported by these facilities. No amounts were outstanding at December 31, 1997.

Utility: The Utility maintains a $1 billion revolving credit facility which expires in 2002. The facility may be extended annually for additional one-year periods upon agreement between the Utility and the banks. At December 31, 1998, the Utility had $567 million of commercial paper outstanding and $101 million of bank notes outstanding. No amounts were outstanding at December 31, 1997.

Wholesale and Retail Unregulated Business Operations: USGen has $1,675 million in revolving credit facilities, of which $575 million is specifically related to its New England operations. The $575 million line is comprised of a $100 million facility, expiring in 2003, and a $475 million facility, used to execute a sale leaseback transaction and subsequently cancelled. As of December 31, 1998, no amounts were outstanding under these facilities. The remaining facility is a $1.1 billion revolving credit agreement comprised of two $550 million facilities, one of which expires in 2003, and the other of which expires in August 1999. As of December 31, 1998, the long-term facility has a $540 million eurodollar loan drawn on it, and it also supports $10 million of outstanding commercial paper. Both are classified as noncurrent debt in the consolidated balance sheet. (See Note 8.) As of December 31, 1998, the short-term facility supported $223 million in outstanding commercial paper, which had a weighted average rate of 5.6 percent.

PG&E GT NW maintains a $200 million revolving credit facility which expires in the year 2000. At December 31, 1998 and 1997, PG&E GT NW had outstanding commercial paper balances of $104 million and $80 million, respectively, supported by this revolving facility. These balances were classified as noncurrent debt in the consolidated balance sheet. (See Note 8.)

PG&E GTT had $70 million and $100 million of outstanding short-term bank borrowings related to two separate credit facilities at December 31, 1998 and 1997, respectively. These lines are cancelable upon demand and bear interest at each respective bank's quoted money market rate. The borrowings are unsecured and unrestricted as to use.

Note 11: Nuclear Decommissioning

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

The estimated total obligation for nuclear decommissioning costs, based on a 1997 site study, is $1.5 billion in 1998 dollars (or $5.1 billion in future dollars). This estimate assumes after-tax earnings on the tax-qualified and nontax-qualified decommissioning funds of 6.16 percent and 5.21 percent, respectively, as well as a future annual escalation rate of 5.5 percent for decommissioning costs. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, and costs of labor, materials, and equipment. The estimated total obligation is being recognized proportionately over the license of each facility.

For the years ended December 31, 1998, 1997, and 1996, nuclear decommissioning costs recovered in rates were $33 million per year, respectively. Based on the 1997 site study, the amount proposed to be recovered in rates in 1999 and annually, until the commencement of decommissioning, is $33 million. This amount is currently under review in the Utility's 1999 General Rate Case and will continue to be reviewed in future nuclear decommissioning cost triennial proceedings.

At December 31, 1998, the total nuclear decommissioning obligation accrued was $1.2 billion and is included in the balance sheet classification of accumulated depreciation and decommissioning. Decommissioning costs recovered in rates are placed in external trust funds. These funds along with accumulated earnings will be used exclusively for decommissioning and cannot be released from the trust funds until authorized by the CPUC.

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

Year ended December 31,	Maturity Dates	1998	1997
(in millions)			
Amortized cost			
U.S. government and agency issues	1999–2028	$ 379	$ 422
Equity securities	—	246	257
Municipal bonds and other	1999–2030	164	70
Gross unrealized holding gains		394	287
Gross unrealized holding losses		(11)	(12)
Fair value (net, of tax)		$1,172	$1,024

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

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

Note 12: Employee Benefit Plans

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

The following schedule reconciles the plans' funded status (the difference between fair value of plan assets and the benefit obligation) to the prepaid or accrued benefit cost recorded on the consolidated balance sheet:

December 31, (in millions)	Pension Benefits		Other Benefits	
	1998	1997	1998	1997
Change in benefit obligation				
Benefit obligation at January 1	$(4,457)	$(4,231)	$(907)	$(921)
Service cost for benefits earned	(108)	(102)	(19)	(22)
Interest cost	(334)	(315)	(64)	(64)
Plan amendments	1	(47)	—	—
Special term benefits	—	(11)	—	(15)
Actuarial gain (loss)	(321)	16	(36)	63
Benefits and expenses paid	242	233	77	52
Benefit obligation at December 31	(4,977)	(4,457)	(949)	(907)
Change in plan assets				
Fair value of plan assets at January 1	6,419	5,526	823	669
Actual return on plan assets	919	1,139	173	144
Company contributions	27	2	18	48
Plan participant contribution	—	—	13	11
Benefits and expenses paid	(261)	(248)	(76)	(49)
Fair value of plan assets at December 31	7,104	6,419	951	823
Plan assets in excess of benefit obligation (Benefit obligation in excess of plan assets)	2,127	1,962	2	(84)
Unrecognized prior service cost	104	121	19	20
Unrecognized net loss (gain)	(2,025)	(2,133)	(430)	(375)
Unrecognized net transition obligation	79	93	366	393
Prepaid (accrued) benefit cost	$ 285	$ 43	$ (43)	$ (46)

The Utility's share of the plan's assets in excess of the benefit obligation for pensions in 1998 and 1997 was $2,134 million and $2,003 million, respectively. The Utility's share of the prepaid (accrued) benefit cost for the pensions in 1998 and 1997 was $301 million and $60 million, respectively.

The plan assets of the Utility exceeded its share of the benefit obligation for other benefits by $24 million in 1998. In 1997, the Utility's share of the benefit obligation in excess of the plan assets was $64 million. The Utility's share of the accrued benefit liability for other benefits in 1998 and 1997 was $26 million and $29 million, respectively.

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

Net benefit income (cost) was as follows:

December 31, (in millions)	Pension Benefits 1998	1997	1996	Other Benefits 1998	1997	1996
Service cost for benefits earned	$(108)	$(102)	$(101)	$(19)	$(21)	$(22)
Interest cost	(333)	(316)	(304)	(64)	(64)	(66)
Expected return on assets	567	486	434	73	60	49
Amortized prior service and transition cost	(26)	(22)	(23)	(28)	(28)	(28)
Actuarial gain (loss) recognized	114	74	43	22	13	4
Benefit income (cost)	$ 214	$ 120	$ 49	$(16)	$(40)	$(63)

The Utility's share of the net benefit income for pensions in 1998, 1997, and 1996 was $215 million, $123 million, and $49 million, respectively.

The Utility's share of the net benefit cost for other benefits in 1998, 1997, and 1996 was $12 million, $38 million, and $61 million, respectively.

Net benefit income (cost) is calculated using expected return on plan assets of 9.0 percent. The difference between actual and expected return on plan assets is included in net amortization and deferral and is considered in the determination of future net benefit income (cost). In 1998, 1997, and 1996, actual return on plan assets exceeded expected return.

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

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

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

December 31,	Pension Benefits 1998	1997	1996	Other Benefits 1998	1997	1996
Discount rate	7.0%	7.5%	7.5%	7.0%	7.5%	7.5%
Rate of future compensation increases	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Expected long-term rate of return on plan assets	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%

The assumed health care cost trend rate for 1999 is approximately 9.0 percent, grading down to an ultimate rate in 2005 of approximately 6.0 percent. The assumed health care cost trend rate can have a significant effect on the amounts reported for health care plans. A one percentage point change would have the following effects:

(in millions)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest cost components	$ 8	$ (7)
Effect on postretirement benefit obligation	$79	$(72)

Long-term Incentive Program: PG&E Corporation maintains a Long-term Incentive Program (Program) which provides for grants of stock options to eligible participants with or without associated stock appreciation rights and dividend equivalents. As of December 31, 1998, 24.5 million shares of common stock have been authorized for award under the program with 10,844,471 shares still available under this plan. At December 31, 1998, stock options on 11,225,564 shares, granted at option prices ranging from $21.125 to $34.25, were outstanding, of which 2,440,008 were exercisable. In 1998, 6,367,100 options were granted at an average option price of $30.52, for an approximate value of $24,258,651 using the Black-Scholes valuation method.

Outstanding stock options expire ten years and one day after the date of grant and become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. In 1998, 1997, and 1996, stock options on 710,271; 235,315; and 72,960 shares, respectively, were exercised at option prices ranging from $16.75 to $34.25. In addition, on January 4, 1999, PG&E Corporation granted 6,173,500 options at $30.9375, the then current market price.

Note 13: Income Taxes

The significant components of income tax expense were:

	PG&E Corporation			Utility		
Year ended December 31,	1998	1997	1996	1998	1997	1996
(in millions)						
Current	$677	$707	$705	$886	$791	$705
Deferred	(52)	(119)	(132)	(201)	(142)	(132)
Tax credits-net	(55)	(40)	(18)	(56)	(40)	(18)
Total income tax expense	$570	$548	$555	$629	$609	$555

The significant components of net deferred income tax liabilities were:

	PG&E Corporation		Utility	
December 31,	1998	1997	1998	1997
(in millions)				
Deferred income tax assets	$1,219	$1,108	$ 843	$ 962
Deferred income tax liabilities:				
Regulatory balancing accounts	43	311	40	311
Plant in service	3,722	3,621	2,930	3,144
Income tax regulatory asset	391	430	381	420
Other	968	924	555	540
Total deferred income tax liabilities	5,124	5,286	3,906	4,415
Total net deferred income taxes	$3,905	$4,178	$3,063	[illegible]
Classification of net deferred income taxes:				
Included in current liabilities	$ 44	$ 149	$ 3	$ 149
Included in noncurrent liabilities	3,861	4,029	3,060	3,304
Total net deferred income taxes	$3,905	$4,178	$3,063	$3,453

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

	PG&E Corporation			Utility		
Year ended December 31,	1998	1997	1996	1998	1997	1996
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	3.3	5.3	3.8	6.6	4.6	3.7
Effect of regulatory treatment of depreciation differences	10.4	8.1	6.0	9.8	7.5	5.9
Tax credits-net	(4.3)	(3.2)	(1.4)	(4.1)	(2.9)	(1.4)
Effect of foreign earnings at different tax rate	.6	(2.2)	—	—	—	—
Other-net	(.8)	.3	—	(1.0)	—	(.8)
Effective tax rate	44.2%	43.3%	43.4%	46.3%	44.2%	42.4%

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

Note 14: Commitments

Utility:

• Letters of Credit:
The Utility uses $385 million in standby letters of credit and surety bonds to secure future workers' compensation liabilities.

• Restructuring Trust Guarantees:
Tax-exempt restructuring trusts have been established to oversee the development of the operating framework for the competitive generation market in California. (See Note 2.) The CPUC has authorized California utilities to guarantee bank loans of up to $[illegible] million to be used by the trusts for this purpose. Under this authorization, the Utility has guaranteed up to a maximum of $135 million of these loans. The bank loans will be repaid and the guarantees removed when the trusts obtain proceeds from permanent financing or rate recovery.

• Power-Purchase Contracts:
By federal law, the Utility is required to purchase electric energy and capacity provided by cogenerators and small power producers. The CPUC established a series of power-purchase contracts and set the applicable terms, conditions, price options, and eligibility requirements.

Under these contracts, the Utility is required to make payments only when energy is supplied or when capacity commitments are met. The total cost of these payments is recoverable in rates. The Utility's contracts with these power producers expire on various dates through 2028. Total energy payments are expected to decline in the years 1999 through 2001. Total capacity payments are expected to remain at current levels during this period. Deliveries from these power producers account for approximately 23 percent of the Utility's 1998 electric energy requirements, and no single contract accounted for more than five percent of the Utility's energy needs.

The Utility has negotiated early termination or suspension of certain power-purchase contracts. These amounts are expected to be recovered in rates and as such are reflected as deferred charges in the accompanying balance sheet. At December 31, 1998, the total discounted future payments remaining under early termination or suspension contracts is $48 million.

The Utility also has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments whether or not any energy is supplied (subject to the supplier's retention of the FERC's authorization) and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. These costs are also recoverable in rates. At December 31, 1998, the undiscounted future minimum payments under these contracts are $32 million for each of the years [illegible] through 2003 and a total of $280 million for [illegible] thereafter. Irrigation district and water agency deliveries in the aggregate account for approximately 7.5 percent of the Utility's 1998 electric energy requirements.

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

Year ended December 31,	1998	1997	1996
(in millions)			
Kilowatt-hours received	25,994	24,389	26,056
Energy payments	943	1,157	1,136
Capacity payments	529	538	521
Irrigation district and water agency payments	53	56	52

• Natural Gas Transportation Commitments:
The Utility has long-term gas transportation service contracts with various Canadian and interstate pipeline companies. For the duration of these contracts, the Utility has agreed to pay the pipeline companies an amount each year for capacity rights on their pipelines. The amount that the Utility pays each year varies due to changes in the rates of the pipeline companies. The

total amounts the Utility paid under these contracts were $113 million, $255 million, and $269 million in 1998, 1997, and 1996, respectively. These amounts include payments made by the Utility to PG&E GT of $49 million, $49 million, and $57 million in 1998, 1997, and 1996, respectively.

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

(in millions)	
1999	$102
2000	102
2001	99
2002	83
2003	83
Thereafter	188
Total	$657

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

Wholesale and Retail Unregulated Business Operations:

• Power-Purchase Contracts:
As a part of the acquisition of a portfolio of electric generating assets and power supply contracts from NEES (See Note 5), NEES transferred to USGen contractual rights and duties under several power-purchase contracts with third-party independent power producers, which in the aggregate provide for approximately 800 MW of capacity. Under the transfer agreement, USGen is required to pay to NEES amounts due to the third-party power producers under the power-purchase contracts. USGen's payment obligations to NEES are reduced by NEES's monthly payment obligation, which equals, in the aggregate, approximately $1.1 billion, payable in monthly installments from September 1998 through January 2008. In certain circumstances, NEES, with the consent of USGen, will make a full or partial lump-sum accelerated payment of the monthly payment obligation to such party as USGen may direct. The approximate dollar obligations under these agreements are as follows:

(in millions)	
1999	$ 261
2000	272
2001	263
2002	238
2003	217
Thereafter	2,024
Total	$3,275

• Natural Gas Transportation Commitments:
As a part of the acquisition of a portfolio of electric generating assets and power supply contracts from NEES (See Note 5), NEES transferred to USGen four natural gas purchase agreements with contract expirations ranging from October 2008 to October 2013, as well as eleven natural gas transportation contracts with contract expirations ranging from October 2006 to October 2014. The approximate dollar obligations under the natural gas transportation agreements are as follows:

(in millions)	
1999	$ 58
2000	58
2001	58
2002	58
2003	57
Thereafter	465
Total	$754

• Standard Offer Agreements:
As a part of the acquisition of a portfolio of electric generating assets and power supply contracts from NEES (See Note 5), USGen entered into agreements to supply the electric capacity and energy necessary for NEES to meet its obligations to provide standard offer service. The agreements to provide standard offer service range in length from 6 to 1[illegible] years. The price per MW hour is standard for all agreements. The approximate dollar obligations under the agreements are as follows:

(in millions)	
1999	$ 788
2000	767
2001	712
2002	483
2003	345
Thereafter	302
Total	$3,397

Note 15: Contingencies

Nuclear Insurance: The Utility has insurance for property damage and business interruption losses as a member of Nuclear Electric Insurance Limited (NEIL). Under this insurance, if a nuclear generating facility suffers a loss due to a prolonged accidental outage, then the Utility may be subject to maximum retrospective assessments of $17 million (property damage) and $5 million (business interruption), in each case per policy period, in the event losses exceed the resources of NEIL.

The Utility has purchased primary insurance of $200 million for public liability claims resulting from a nuclear incident. The Utility has secondary financial protection which provides an additional $9.6 billion in coverage, which is mandated by federal legislation. It provides for loss sharing among utilities owning nuclear generating facilities if a costly incident occurs. If a nuclear incident results in claims in excess of $200 million, then the Utility may be assessed up to $176 million per incident, with payments in each year limited to a maximum of $20 million per incident.

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

The Utility records a liability when site assessments indicate remediation is probable and a range of reasonably likely cleanup costs can be estimated. The Utility reviews its remediation liability quarterly for each identified site. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The remediation costs also reflect: (1) current technology, (2) enacted laws and regulations, (3) experience gained at similar sites, and (4) the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the lower end of this range.

The cost of the hazardous substance remediation ultimately undertaken by the Utility is difficult to estimate. A change in the estimate may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility had an accrued liability of $296 million and $232 million at December 31, 1998 and 1997, respectively, for hazardous waste remediation costs at identified sites, including divested fossil-fueled power plants.

Environmental remediation at identified sites may be as much as $487 million if, among other things, other potentially responsible parties are not financially able to contribute to these costs or further investigation indicates that the extent of contamination or necessary remediation is greater than anticipated. The Utility estimated this upper limit of the range of costs using assumptions least favorable to the Utility, based upon a range of reasonably possible outcomes. Costs may be higher if the Utility is found to be responsible for cleanup costs at additional sites or expected outcomes change.

Of the $296 million liability, discussed above, the Utility has recovered $104 million and expects to recover another $160 million in future rates. Additionally, the Utility mitigates its cost by seeking recovery of its costs from insurance carriers and from other third parties as appropriate.

Legal Matters:

• Chromium Litigation:

Several civil suits are pending against the Utility in California state courts. The suits seek an unspecified amount of compensatory and punitive damages for alleged personal injuries and, in some cases, property damage, resulting from alleged exposure to chromium in the vicinity of the Utility's gas compressor stations at Hinkley, Kettleman, and Topock, California. Two of these suits also name PG&E Corporation as a defendant. Currently, there are claims pending on behalf of approximately 2,300 individuals.

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

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

• Texas Franchise Fee Litigation:
In connection with PG&E Corporation's acquisition of Valero Energy Corporation, now known as PG&E GTT, PG&E GTT succeeded to the litigation described below.

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

In 1998, a jury trial was held in the separate suit brought by the City of Edinburg (the City). This suit involved, among other things, a particular franchise agreement entered into by a former subsidiary of PG&E GTT (now owned by Southern Union Gas Company (SU)) and the City and certain conduct of the defendants.

On December 1, 1998, based on the jury verdict, the court entered a judgment in the City's favor, and awarded damages of $5.3 million, and attorneys' fees of up to $3.5 million plus interest. The court found that various PG&E GTT and SU defendants were jointly and severally liable for $3.3 million of the damages and all the attorneys' fees. Certain PG&E GTT subsidiaries were found solely liable for $1.4 million of the damages. The court did not clearly indicate the extent to which the PG&E GTT defendants could be found liable for the remaining damages. The PG&E GTT defendants intend to appeal the judgment.

PG&E Corporation believes that the ultimate outcome of these matters could have a material adverse impact on its financial position or results of operations.

Note 16: Segment Information

PG&E Corporation's reportable operating segments provide different products and services and are subject to different forms of regulation or jurisdictions. The accounting policies of the reportable operating segments are the same as those described in Note 1. PG&E Corporation's reportable segments are described below.

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

Wholesale Unregulated Business Operations: PG&E Corporation's wholesale unregulated business operations consist of USGen which develops, builds, operates, owns, and manages power generation facilities that serve wholesale and industrial customers, PG&E GT which operates approximately 9,000 miles of natural gas pipelines, natural gas storage facilities, and natural gas processing plants in the Pacific Northwest and Texas; and PG&E ET which purchases and resells energy commodities and related financial instruments in major North American markets, serving PG&E Corporation's other unregulated businesses, unaffiliated utilities, and large end-use customers.

Retail Unregulated Business Operations: PG&E Corporation's retail unregulated business operations consist of PG&E ES which provides competitively priced electricity, natural gas, and related services to lower overall energy costs for industrial, commercial, and institutional customers.

Segment information for the years 1998, 1997, and 1996 was as follows:

		Wholesale				Retail			
			PG&E GT						
(in millions)	Utility	USGen[5]	NW	Texas[5]	PG&E ET	PG&E ES	Corp. & Other[2]	Eliminations	Total
1998									
Operating revenues	$ 8,919	$ 645	$ 185	$1,640	$8,183	$365	$ 8	$ (3)	$19,942
Intersegment revenues[1]	5	4	52	301	326	14	—	(702)	—
Total operating revenues	8,924	649	237	1,941	8,509	379	8	(705)	19,942
Depreciation, amortization and decommissioning	1,438	52	39	65	5	7	3	—	1,609
Interest expense[3]	(621)	(43)	(43)	(77)	(7)	(1)	(30)	40	(782)
Other income (expense)	76	18	3	13	5	(1)	(6)	(44)	64
Income taxes[4]	629	28	31	(47)	(17)	(41)	(13)	—	570
Net income	702	106	65	(71)	(6)	(52)	(18)	(7)	719
Capital expenditures	1,396	98	49	39	12	38	1	—	1,633
Total assets at year-end	$22,950	$3,844	$1,169	$2,655	$2,555	$202	$601	$ (742)	$33,234
1997									
Operating revenues	$ 9,495	$ 148	$ 186	$ 800	$4,613	$145	$ 13	$ —	$15,400
Intersegment revenues[1]	—	—	47	204	195	—	—	(446)	—
Total operating revenues	9,495	148	233	1,004	4,808	145	13	(446)	15,400
Depreciation, amortization and decommissioning	1,748	19	38	33	3	1	10	—	1,852
Interest expense[3]	(570)	(5)	(41)	(26)	(2)	(1)	(32)	12	(665)
Other income (expense)	83	(25)	1	13	3	—	138	(12)	201
Income taxes[4]	609	(17)	26	(8)	(12)	(17)	(33)	—	548
Net income	735	(41)	40	(24)	(19)	(29)	54	—	716
Capital expenditures	1,529	23	34	45	5	15	50	—	1,701
Total assets at year-end	$25,147	$ 989	$1,208	$2,800	$1,452	$ 60	$370	$(911)	$31,115
1996									
Operating revenues	$ 8,989	$ 105	$ 206	$ —	$ 283	$ —	$ 27	$ —	$ 9,610
Intersegment revenues[1]	—	—	58	—	—	—	—	(58)	—
Total operating revenues	8,989	105	264	—	283	—	27	(58)	9,610
Depreciation, amortization and decommissioning	1,177	12	32	—	—	—	1	—	1,222
Interest expense[3]	(600)	(7)	(45)	—	—	—	20	—	(632)
Other income (expense)	20	9	(4)	—	—	—	(12)	—	13
Income taxes[4]	526	(6)	31	—	—	—	4	—	555
Net income	706	(6)	50	—	—	—	(28)	—	722
Capital expenditures	1,231	—	173	—	—	—	—	—	1,404
Total assets at year-end	$23,567	$ 881	$1,772	$ —	$ —	$ —	$205	$ (188)	$26,237

[1] Intersegment electric and gas revenues are recorded at market prices, which for the Utility and PG&E GT NW are tariffed rates prescribed by the CPUC and FERC, respectively.
[2] Assets of PG&E Corporation are included in the Other column exclusive of investment in its subsidiaries.
[3] Net interest expense incurred by PG&E Corporation is allocated to the segments using specific identification.
[4] Income tax expense for the Utility is computed on a stand-alone basis. The balance of the consolidated income tax provision is allocated among the unregulated wholesale and retail segments.
[5] Income from equity-method investees for 1998, 1997, and 1996 was $113 million, $41 million, and $36 million, respectively, for USGen, and $3 million and $2 million, respectively, for PG&E GT Texas.

Quarterly Consolidated Financial Data (Unaudited)

Quarter ended (in millions, except per share amounts)	December 31	September 30	June 30	March 31
1998				
PG&E Corporation				
Operating revenues	$5,495	$5,307	$4,787	$4,353
Operating income	456	529	557	465
Net income	196		174	139
Earnings per common share, basic and diluted	.51		.46	.36
Dividends declared per common share	.30		.30	.30
Common stock price per share				
High	35.00	33.3	33.19	33.19
Low	30.44	30.0[illegible]	30.13	29.38
Utility				
Operating revenues	$2,218	$2,563	$2,117	$2,026
Operating income	443	513	494	426
Income available for common stock	169	199	186	148
1997				
PG&E Corporation				
Operating revenues	$4,889	$4,063	$3,083	$3,365
Operating income	265	628	371	464
Net income	94	257	193	172
Earnings per common share, basic and diluted	.22	.62	.49	.42
Dividends declared per common share	.30	.30	.30	.30
Common stock price per share				
High	30.94	24.94	25.00	24.25
Low	23.00	22.69	22.38	20.88
Utility				
Operating revenues	$2,401	$2,541	$2,279	$2,274
Operating income	390	626	370	445
Income available for common stock	180	269	122	164

Report of Independent Public Accountants

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

We have audited the accompanying consolidated balance sheets of PG&E Corporation (a California corporation) and subsidiaries and Pacific Gas and Electric Company (a California corporation) and subsidiaries as of December 31, 1998, and 1997, and the related statements of consolidated income, cash flows, and common stock equity of PG&E Corporation and subsidiaries and the related statements of consolidated income, cash flows and common stock equity, preferred stock and preferred securities of Pacific Gas and Electric Company and subsidiaries for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the management of PG&E Corporation and Pacific Gas and Electric Company. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial positions of PG&E Corporation and subsidiaries, and of Pacific Gas and Electric Company and subsidiaries, as of December 31, 1998, and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP
San Francisco, California
February 8, 1999

Responsibility for Consolidated Financial Statements

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

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

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

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

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

Shareholder Information

Shareholder Services Office
77 Beale Street, Room 2600
San Francisco, CA 94105
Call Toll Free 1.800.367.7731
Fax 415.973.7831

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

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

Manager of Shareholder Services
David M. Kelly
Mail Code B26B
P.O. Box 770000
San Francisco, CA 94177
1.800.367.7731

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

Vice President and Corporate Secretary
Leslie H. Everett
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105
415.267.7070

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

Manager of Investor Relations
David E. Kaplan
One Market, Spear Tower, Suite 2400
San Francisco, CA 94105
415.267.7080

PG&E Corporation
General Information
415.267.7000

Pacific Gas and Electric Company
General Information
415.973.7000

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

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

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

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

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

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

Date: April 21, 1999
Time: 10:00 a.m.
Location: Masonic Auditorium
1111 California Street
San Francisco, California

A joint notice of the annual meetings, joint proxy statement, and proxy form are being mailed with this annual report on or about March 8, 1999, to all shareholders of record as of February 22, 1999.

10-K Report

If you would like a copy of the 1998 Form 10-K Report to the Securities and Exchange Commission, please contact the Shareholder Services Office, or visit our web sites, www.pgecorp.com and www.pge.com.

1999 Dividend Payment Dates

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

Stock Exchange Listings

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

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

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

[1] Local newspaper symbols may vary

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