Pacific
Gas and Electric
Company

P G & E

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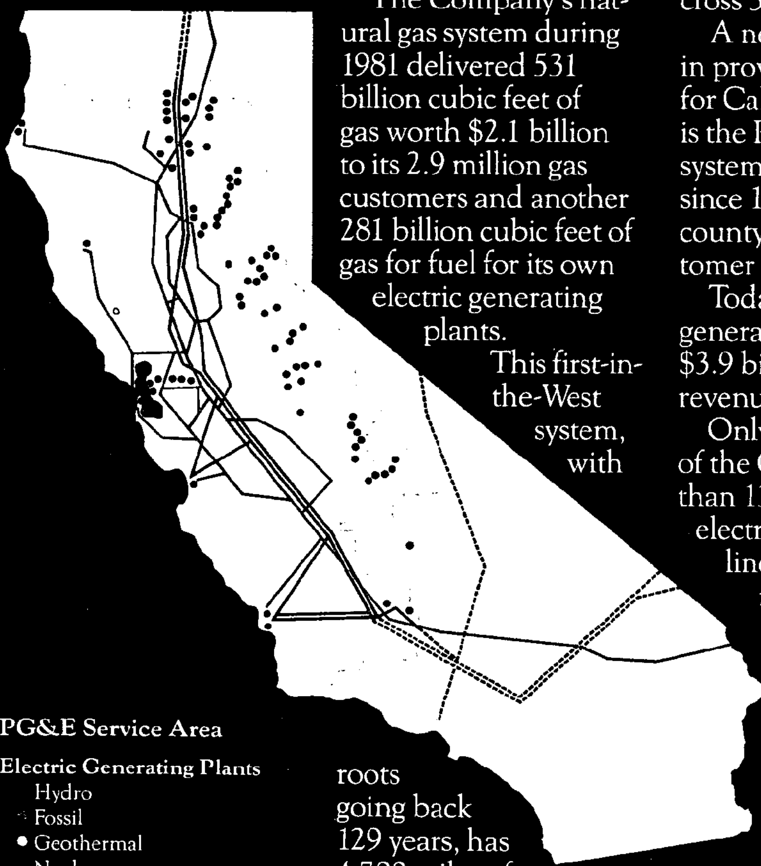
Annual Report

Serving Nearly 10 Million Californians

PG&E, with its gas and electric operations serving nearly half the residents of California, is the largest combination utility in the United States based on revenues.

The Company's natural gas system during 1981 delivered 531 billion cubic feet of gas worth $2.1 billion to its 2.9 million gas customers and another 281 billion cubic feet of gas for fuel for its own electric generating plants.



This first-in-the-West system, with roots going back 129 years, has 4,700 miles of Company-owned transmission lines bringing gas from Canada, the Southwest, the Rocky Mountain area, and from wells in California.

Nearly 30,000 miles of distribution lines crisscross 37 counties.

A near-equal pioneer in providing energy for California's growth is the PG&E electric system, ever-expanding since 1879 into a 47-county, 3.5 million customer operation.

Today, that system generates about $3.9 billion in annual revenues.

Only the very largest of the Company's more than 13,000 miles of electric transmission lines appear on the map, pinpointing PG&E's 65 hydroelectric plants, 13 thermal plants, and major gas interties.

Highlights

	1981	1980	% Change
Operating Revenues	$ 6,194,575,000	$ 5,258,899,000	18%
Net Income	$ 564,606,000	$ 524,770,000	8%
Earnings Available for Common	$ 430,907,000	$ 415,601,000	4%
Earnings Per Common Share	$3.41	$3.60	-5%
Dividends Declared Per Common Share	$2.72	$2.60	5%
Total Assets	$12,366,659,000	$11,295,203,000	9%
Construction Expenditures	$ 1,383,714,000	$ 1,221,758,000	13%
Sales of Electricity to Customers (KWH)	61,668,546,000	58,291,655,000	6%
Sales of Gas to Customers (MCF)	531,293,000	558,892,000	-5%
Total Customers	6,421,076	6,316,244	2%
Number of Stockholders	397,016	402,985	-1%
Number of Employees	26,625	27,582	-3%

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To Our Stockholders

Major events of 1981 that will bear importantly on the Company's future were:

A substantial increase in the Company's general rates granted by the California Public Utilities Commission (CPUC) on December 30.

A substantial improvement in the Company's cash flow, starting in 1982, because of mandated normalization of tax benefits under the Economic Recovery Tax Act of 1981.

Adoption by the Company of strengthened programs to achieve key corporate goals and attain financial health.

Suspension of the Company's low power testing license for Diablo Canyon nuclear power plant because of late-discovered design errors in the plant.

The remainder of this letter will discuss these several events.

Rates and Financial Condition

The unsatisfactory financial results for 1981—$3.41 per share, or 11.3 percent return on common stock equity—came as no surprise. It was the inevitable consequence of selling our product below cost.

In the past, our rates have been consistently fixed at less than needed to cover rapidly escalating costs, including capital costs.

As a result, over the past several years, PG&E has experienced a deterioration in its financial condition.

This, and the difficulty of licensing Diablo Canyon, were significant factors accounting for the low price of the Company's common stock in 1981. At year-end, the stock was selling at a price approximately two-thirds of its book value.

Because a financially healthy Company benefits both customers and stockholders, your Company has aggressively pursued its application for higher general rates.

On December 30, 1981, the California Public Utilities Commission rendered a decision on our application and increased the Company's general rates by $834 million annually (including the benefits from the new tax act described below).

By these actions the Commission seemed to recognize the costly realities of providing energy in today's economic environment, but chose to reject full cost recovery in favor of moderating the price increase to our customers.

The result of the Commission's disallowances will necessarily be a scaling back of our operations to match the limits of the revenues allowed. Unfortunately, this will mean some reduction in the high level of service that our customers have come to expect from us over the years.

Even though we received less than requested, our dedication to operate the Company within the constraints of this rate decision provides a beginning for significantly improved financial results.

The allowed 16 percent return on equity is an improvement over the 14.1 percent previously determined to be fair and reasonable two years ago.

"A financially healthy Company benefits both customers and stockholders."

Unfortunately, the decision did not adopt all the procedures we requested which would have added to cash flow and reduced our current over-reliance on external financing. The CPUC also refused to increase rates sufficiently to cover all the expenses which we believe are required to provide adequate service to our customers.

Cash Flow Improvement

The Economic Recovery Tax Act enacted by Congress in 1981 requires rate regulatory authorities to "normalize" rather than "flow through" certain federal income tax benefits when setting general rates for utilities.

In accordance with this Act, the CPUC's general rate decision of December 30 includes cash flow benefits of approximately $177 million in 1982.

This reduces the Company's need for external financing in 1982 by the same amount—a substantial benefit during current times of high capital costs.

Reduced external financing not only saves high borrowing costs, but lessens the need to issue additional shares of common stock at below-book prices with resulting dilution of existing stockholders' equity.

Corporate Goals and Financial Health

The cornerstone of the Company's goals is attainment of financial health. In furtherance of this objective, we have adopted a number of specific programs to:

operate within revenue and expense levels provided by rate case decisions;

minimize capital expenditures;

avoid major commitments of capital to new energy supply projects involving long lead times and high risk, until financial health is achieved;

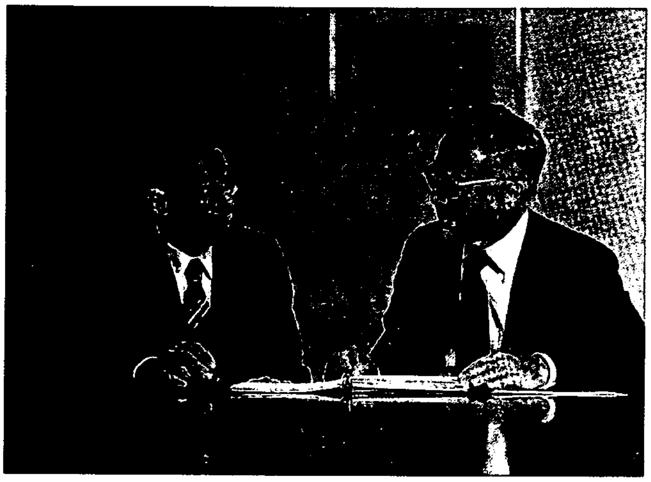
improve employee competence and productivity;

increase efficiency in operations; and

pursue changes in regulation and institutional arrangements to reduce to acceptable levels the risks associated with Company financing of new major energy projects.

In many respects—particularly in regard to future sources of electric energy and natural gas—this new corporate direction contrasts sharply with that which the Company was able to adopt during the 1950s and 1960s.

During that period we were able to invest substantial amounts of capital in projects to add new energy resources to the Company's system, including those that would reduce dependence on oil and natural gas for power plant fuel.



Frederick W. Mielke, Jr. *Barton W. Shackelford*

Now we are planning to avoid major commitments of capital to new energy supply projects until such time as (1) our financial goal is achieved, (2) the Diablo Canyon nuclear plant and the Helms Creek pumped storage project are included in the Company's rate base, and (3) regulatory and technological risks in major new undertakings are reduced to acceptable levels.

In adopting this direction, we will rely to an increasing extent on purchasing from other suppliers our future additions of gas and electric power supplies, rather than investing Company capital to provide these supplies.

This course involves some risk regarding the adequacy of the Company's future electric and gas supplies.

We will work aggressively to avoid this risk, but we cannot continue operations which cause the financial health of the Company to deteriorate. The long-term interests of both customer and stockholder require a financially strong PG&E.

Diablo Canyon

Among those corporate goals which are not new and which have long occupied a position of corporate priority are our commitments to:

Complete all work and obtain operating licenses for Units 1 and 2 of the Diablo Canyon nuclear plant;

Operate the Diablo Canyon nuclear plant, when licensed, at the highest level of safety and with the lowest incidence of outages.

On September 22, 1981, we received a license to load fuel and test Unit 1 up to 5 percent capacity. Six days later, on September 28, we discovered certain diagram errors. We reported them to the Nuclear Regulatory Commission (NRC) and immediately ceased all fuel-loading procedures.

The error resulted from an inexcusable failure to follow our well-established quality control procedures. On the basis of the extensive design review conducted thus far, we believe that no consequences for the safety of the plant and the general public would have resulted if this problem had gone undetected.

Notwithstanding the fact that the Company had already engaged outside consultants to conduct reverification analyses and had committed to make all modifications before resuming operations, the NRC suspended our low-power license on November 19.

Based upon an extensive seismic safety reverification program by independent consultants, no major design errors at the plant have been found to date.

The plant modifications thus far required as a result of the reverification program are relatively minor and, in the aggregate, are expected to cost less than one million dollars.

As a result, we remain optimistic that the licensing process can soon be concluded and Unit 1 placed in operation during the third quarter of 1982.

Diablo Canyon is vitally needed by the area we serve. It will increase PG&E's generating capacity by about 20 percent and help to restore area reserve margins to more reliable levels. In full operation, the plant will generate annually the energy equivalent of 20 million barrels of fuel oil.

We estimate that in just the first ten years of operation the plant will save our customers more than $5 billion in their rates because of Diablo's lower generating cost compared to alternative means of generation that would otherwise be needed.

The Future

We have a competent, unified and dedicated work force which gives us great confidence that our corporate goals will be achieved.

With achievement of our goals, we can look forward to a future of quality service to our customers and a fair return to our stockholders.

Frederick W. Mielke, Jr.
Chairman of the Board and
Chief Executive Officer

Barton W. Shackelford
President and
Chief Operating officer
February 12, 1982

OPERATIONS

Finance

Net Income Up By $40 Million

Kilowatt hours of electricity sold in 1981 increased six percent from 1980 to an all-time high. Revenues from electric sales increased 33 percent because of higher rates which partially offset higher costs.

Volumes of gas sold in 1981 declined five percent, but higher rates limited the decrease in gas revenues to only two percent.

Overall, operating revenues rose 18 percent. This was exactly matched by an 18 percent rise in overall operating expenses.

Net income for the year came to $565 million, an increase of $40 million over 1980. After preferred dividend requirements of $134 million, $431 million was available for common stockholders, equivalent to $3.41 per share.

This was a decrease of 19 cents from the $3.60 per share a year ago.

Return on common stockholders' equity was 11.3 percent, compared with 11.7 percent the previous year, both figures being substantially below the 14.1 percent return found fair and reasonable by the California Public Utilities Commission (CPUC) when it set our 1980 and 1981 rates.

The Company's financing program during 1981 totaled approximately $1 billion, including a Eurobond and an adjustable rate bond. These two issues were new financing vehicles for PG&E as the Company pursued the course of finding the least expensive financing arrangements possible commensurate with its needs for long-term capital.

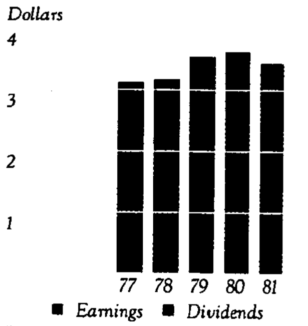
Further description of 1981 operating expenses and net income is included in our Management's Discussion on Pages 17 and 18.

Reinvestment of Dividends To Defer Taxes

The Company's Dividend Reinvestment and Common Stock Purchase Plan is undergoing change to qualify the Plan for tax deferred treatment under the Economic Recovery Tax Act of 1981.

Under the new Tax Act, individual common and preferred stockholders in a public utility may defer federal income taxes on common and preferred dividends they receive in 1982 through 1985 to the extent of $750 ($1,500 for a joint return) by reinvesting the dividends in new common stock of the utility through a qualified Dividend Reinvestment Plan.

Earnings Per Share and Dividends Declared



In general, gain from the sale of stock acquired with reinvested dividends will be eligible for capital gains treatment. However, where a stockholder sells common stock (up to the amount of the reinvested dividend) after the record date for the distribution and not more than one year after distribution of the reinvested dividend, all proceeds will be treated as ordinary income.

When the Company qualifies its Plan for purposes of the new Tax Act, hopefully by April 15, stockholders will receive a prospectus, giving full details.

Currently more than 50,000 PG&E stockholders are participants in the Plan which raised $41 million of new equity funds for the Company in 1981.

Rates

Rate Increases Top $1 Billion

During 1981, a total of ten rate adjustments by the California Public Utilities Commission resulted in rate increases of approximately $1.3 billion, on an annualized basis, being granted the Company.

Four of these rate adjustments were "offsets" designed to pass along to customers dollar-for-dollar the costs incurred by the Company for the purchase of fuel oil, natural gas, and electric power produced by others.

These "fuel-related" costs comprise the largest single category of expense in the Company's operations, and required 64 percent of all revenues collected from our customers in 1981. The net additional revenues realized during the year from fuel-related rate adjustments amounted to approximately $1.2 billion.

In addition, PG&E received an interim general rate increase in the amount of $155 million to cover the higher costs of non-fuel-related expenses such as labor, material and financing costs.

The Company also received five other increases intended to offset the costs incurred for gas exploration and development and to implement new conservation programs. The additional revenues realized during the year from these pass-through rate adjustments amounted to approximately $34 million.

Thus, only 14 percent of the total increases were not fuel-related.

As a result of these significantly higher rates, the CPUC has focused greater attention in recent years on the allocation of rate increases between customer classifications.

Natural gas, for example, has been priced with reference to the prices that large industrial customers would pay for alternative sources of energy.

This "alternate fuel price" has served as the benchmark rate for industrial customers, with other customer classes contributing the remainder of the authorized revenues according to established relationships. The intent of this pricing philosophy is to ensure that customers pay incremental costs at least for discretionary uses.

Electric rates fixed by the Commission are designed to encourage conservation.

Rate structures, such as residential rates which increase for higher levels of use, time-of-use rates for all customer classes, and interruptible rates, constitute a program intended to promote efficient energy use and thereby lessen the need to provide future, high-cost energy supplies.

The CPUC's 1981 decisions reinforced its commitment to conservation and efficiency, and authorized PG&E to continue to pursue these goals through rate and load management programs.

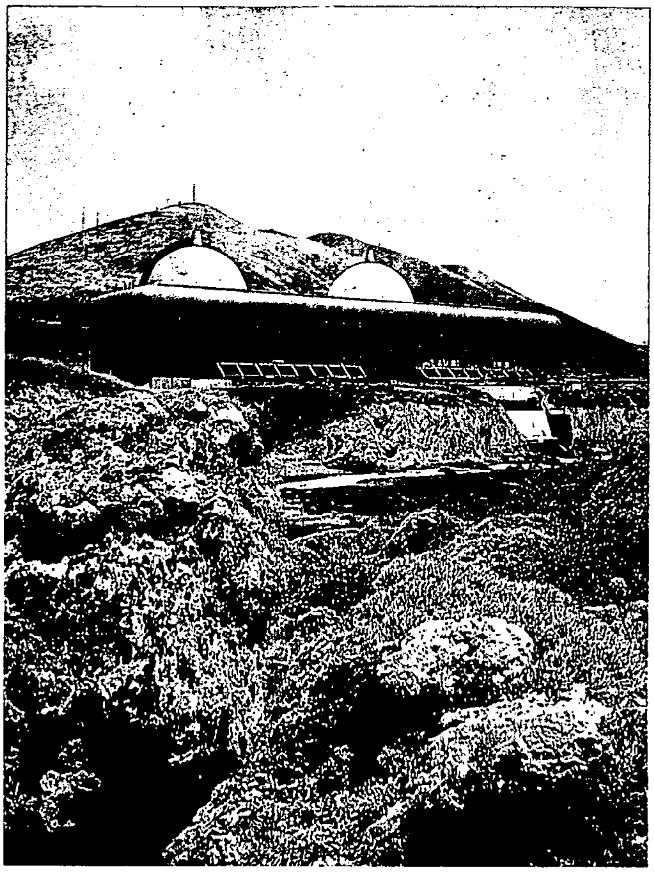
For 1982, the Company requested a general rate increase of $1.3 billion. This included $359 million for improved cash flow procedures and $941 million for increases in non-fuel-related costs, such as labor, materials, and return on invested capital.

An overall rate of return of 12.86 percent was sought for total invested capital and 18 percent for common equity.

On December 30, the CPUC granted $834 million of the $1.3 billion request. The granted amount included $177 million for improved cash flow under the normalization provisions of the Economic Recovery Tax Act of 1981. This decision authorized an overall rate of return of 12.2 percent and a rate of return on common equity of 16 percent.

In addition, the CPUC established a procedure for the first time that eliminates the possibility of revenue shortages from declines in electric sales. A similar procedure for gas sales has been in effect since 1978.

The decision also authorized an adjustment in rates in 1983 to offset the impact of inflation. The amount of the adjustment is determined in part by the use of inflation indexes.



The Company estimates that the required design review of its two-unit Diablo Canyon Nuclear Power Plant can be completed by the end of June 1982 and that Unit 1 could be licensed for full power operation by mid-year.

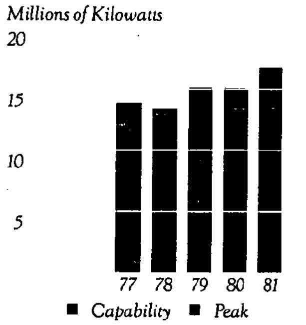
Electric Operations

Peak Electric Demand Sets All-Time Record

Unseasonably hot weather on June 22 sent electric peak demand in the PG&E area to an all-time high of 15.5 million kilowatts.

A reserve of 5.9 percent was maintained by power purchased from other utilities, by interruption of power to State Water Project pumps, and by load management programs including automatic cycling of residential air conditioners.

Electric Peak and Above Peak Capability
PG&E System



Hydro Expansion Aims At Fossil Fuel Cutback; Lower Cost Generation

The rising cost of fossil fuel to generate electricity has directed Company planning toward enlarging its present 65-plant hydroelectric system.

A companion goal is to keep this efficient, integrated system intact by obtaining renewal of all federal licenses and preventing takeover by certain municipal electric systems, which seek to divert the benefits of those projects from PG&E customers to their own.

Company hydro projects on the Mokelumne and Feather rivers call for enlarging and improving existing facilities and adding eight new powerhouses.

Proposed additions would increase capacity by 60,500 kilowatts and produce additional energy equivalent to burning 406,000 barrels of oil a year in thermal generating plants.

The Company also filed license applications with the Federal Energy Regulatory Commission in 1981 for seven other hydro projects on other watersheds that could increase system capacity by 34,600 kilowatts and produce energy equivalent to burning 290,000 barrels of oil annually.

PG&E plans to file license applications for additional projects in 1982.

Construction Continues At Helms, Kerckhoff 2 Underground Powerhouses

Meanwhile in 1981, construction continued at Helms Pumped Storage Project and Kerckhoff 2 Powerhouse in the Sierra east of Fresno.

These projects are scheduled for completion by early 1983.

The Helms Project will provide 1,120,000 kilowatts of pumped storage hydro capacity to meet peak loads.

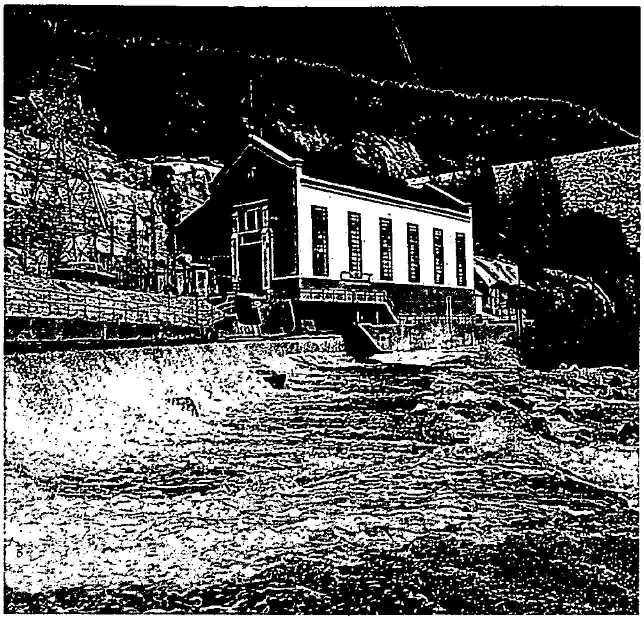
Kerckhoff 2 will add 140,000 kilowatts of new hydro generation to the 2,517,700 kilowatts of hydro power now in the Company's system.

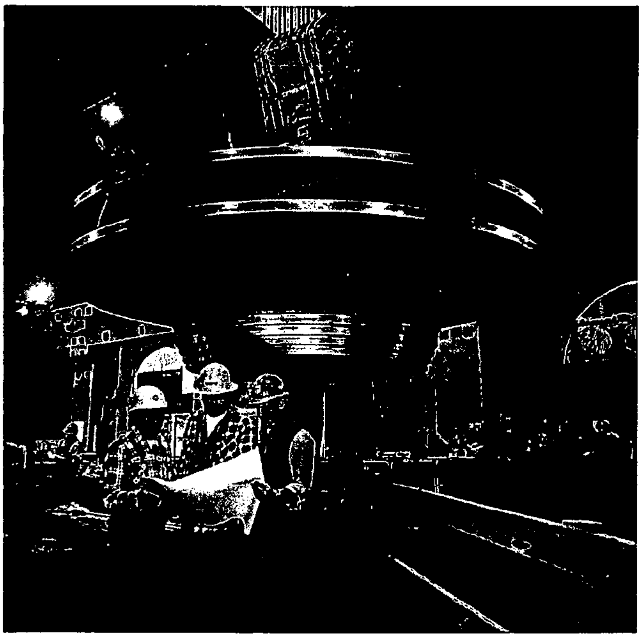
In addition, the 1,000-kilowatt Volta 2 Powerhouse near Red Bluff was completed on schedule during 1981.

The Volta project is part of Company plans to continue its own hydro construction while also participating through power purchases in small, cost-effective hydro plants built by others.

The Company now buys power from nine public agencies, such as irrigation districts, which own and operate hydro facilities. Construction began in 1981 on seven new projects from which PG&E will purchase the power output.

In addition, more than 200 small hydro projects have been proposed by developers within the Company's service area.





Company planning includes ways to enlarge and improve the efficiency of its 65-powerhouse hydroelectric system—PG&E's lowest cost source of power. For example, an additional generating unit is proposed at the existing Salt Springs Powerhouse on the Mokelumne River, shown at top.

Contractor workers, observed by a PG&E inspector in yellow hat, install one of three powerful pump-turbines at the Helms Pumped Storage Project powerhouse—a chamber longer than a football field and hewn out of solid granite 1,000 feet below the surface of a Sierra mountain.

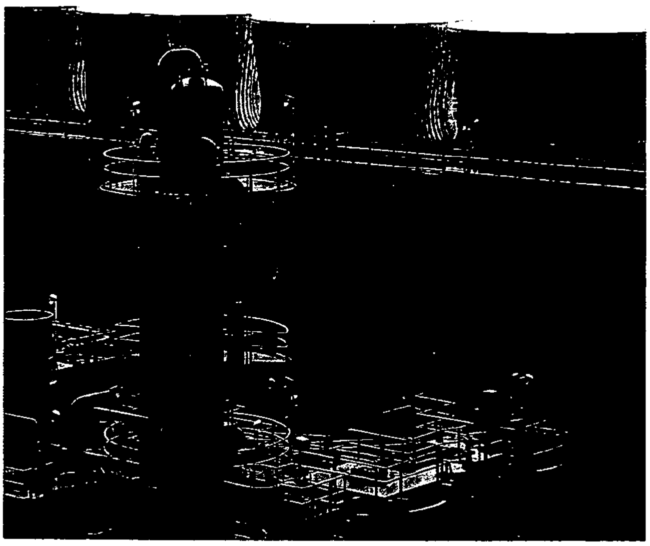
Geothermal Generation Development Continues

Progress toward full development of The Geysers project— PG&E's unique, economical source of power derived from geothermal steam—centered on construction of two 110,000-kilowatt units for operation in 1983.

Each unit will generate electricity to serve about 100,000 customers and save burning more than one million barrels of oil a year.

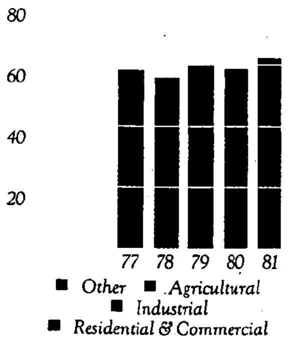
A third identical unit and associated 38-mile transmission line was approved by the California Energy Commission in October. It is expected to join 15 units already on line by 1985-1986.

The 18 units of various sizes in Sonoma and Lake counties will then have capacity of more than 1.2 million kilowatts.



Geothermal power development by PG&E continues at The Geysers 80 miles north of San Francisco, where 15 units together provided nearly eight percent of the PG&E system's 1981 energy requirements. A new process, shown here, removes hydrogen sulfide gas from naturally occurring underground steam.

Uses of Electric Energy



Further additions to the PG&E system at this largest geothermal power installation in the world may ultimately provide two million kilowatts of capacity and save burning the equivalent of more than 20 million barrels of oil annually in other thermal power stations.

Alternative Energy Sources Include Wind, Cogeneration

In 1980, the Company announced plans to have 54 percent of its additions to generating capacity in the 1980s come from alternative energy sources and other preferred and renewable resources. This was the largest such commitment of any utility in California and, to our knowledge, the largest of any utility in the country.

Last year, we increased our commitment and now plan to have almost 60 percent of our new generating capacity in the 1980s come from these resources.

Alternative resources are attractive because they do not burn oil or gas, require less lead time to complete than large central station base-load plants, require either no capital, or very little, to be provided by the Company, and generally can be built with fewer regulatory problems and less risk in meeting completion dates.

The Company has advanced plans for three major wind power farms, a large wind turbine demonstration project, and many agreements with homeowners and others who install small wind generators on their premises.

At year's end, power was generated into PG&E's system from the first machine at a hilltop wind farm in eastern Alameda County, 50 miles east of San Francisco. This agreement with U.S. Windpower, Inc. calls for purchasing power from as many as 600 such turbines, each capable of generating 50 kilowatts for a total of 30,000 kilowatts.

Nearby, another 30 wind turbines, each capable of generating 56 kilowatts for a total of 1,680 kilowatts, are under construction as part of a potential 300-turbine wind farm involving the Fayette Manufacturing Corporation and Farrell O'Keefe Properties.

The Company has a contract to purchase power from this project beginning in 1982.

A third project will be owned and operated by Windfarms, Ltd. The first 92,500-kilowatt stage of this project will be developed in Solano County, about 30 miles northeast of San Francisco.

Full development of the project will consist of 146 large wind turbine-generators with an aggregate capacity of 350,000 kilowatts.

PG&E plans to purchase most of the energy from this project—largest of any wind power development anywhere in the world. The California Department of Water Resources will buy a portion of the off-peak power for State Water Project pumping operations.

Also in Solano County, a 350-foot high Boeing MOD-2 wind turbine-generator was near completion at the close of 1981. This PG&E demonstration project will supply 2,500 kilowatts to the Company's system in 1982.

In addition by year's end, PG&E had agreements to purchase power from nearly 50 small, single-owner wind generators in the 1.5 to 25 kilowatt range.

Thus, current contracts provide for an ultimate installation of about 383,000 kilowatts of wind turbine capacity, which could reduce fossil fuel requirements by more than 1.4 million barrels of oil per year.

Discussions are under way with many other homeowners, farmers, and businessmen as possible participants in the Company's wind program.

In furtherance of the Company's goal of avoiding major commitments of capital for new energy projects, capital for wind-powered generators is being supplied by others, who also take the financial risk of completion. The Company pays only for the energy actually produced by the wind machines and delivered into the PG&E system.

PG&E's wind program is by far the largest planned by any utility in the country.

In 1981, the Company also advanced on other alternative energy fronts such as biomass, solid waste, and cogeneration projects. The latter projects permit the Company to purchase power from local industries and institutions having their own generating facilities.

During 1981, the Company signed contracts to acquire the output of 20 cogeneration and solid waste projects, which will have a capacity of nearly 200,000 kilowatts.

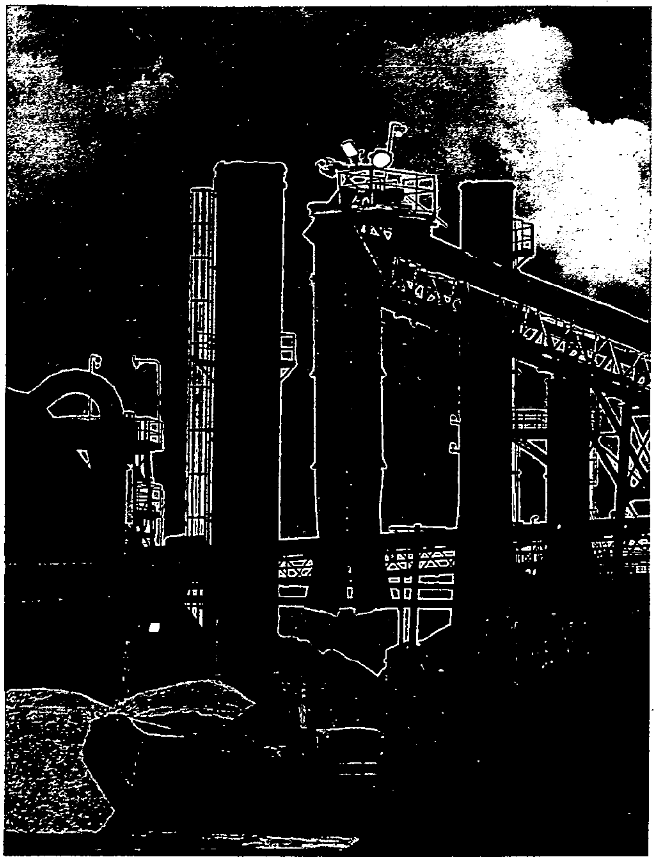
Planned projects already under contract, plus existing cogeneration facilities, now total more than 800,000 kilowatts.

PG&E also is constructing and evaluating cogeneration projects at its own facilities, including gas compressor station sites.

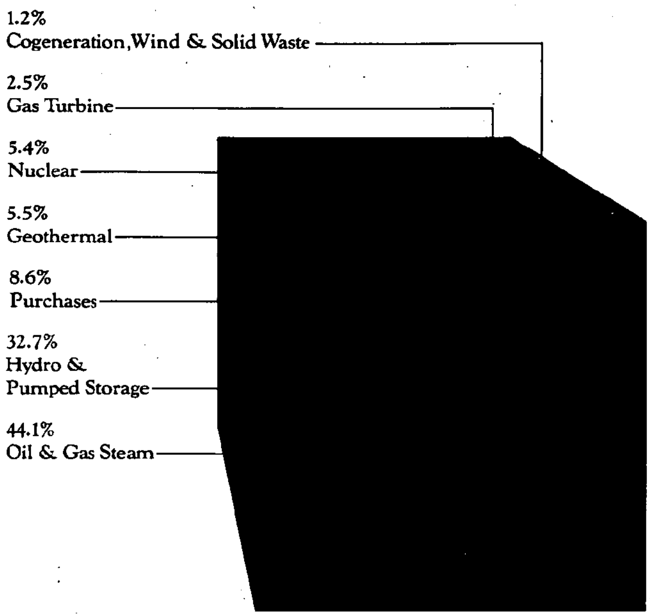
The Company, too, is encouraging industry not wishing to invest directly in cogeneration to consider third-party financing.

It is also providing guidance to potential cogenerators in economic evaluation and environmental qualification of such facilities.

Particularly noteworthy in the effort to further these alternative energy projects

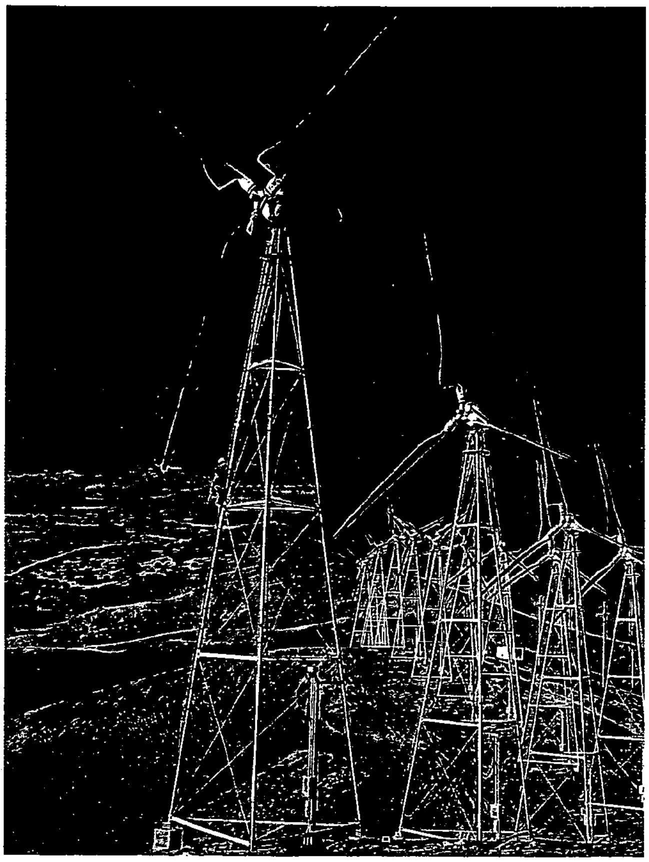


Cogeneration in action. At the Louisiana-Pacific Corporation facility near Eureka, wood that might otherwise be wasted is burned—both to generate process steam and electricity in that company's power plant for its forest products complex. The excess power is sold to PG&E.



The PG&E Area resource mix, shown above, includes the PG&E System plus the Sacramento Municipal Utility District and other publicly owned electric systems in Northern and Central California, all of which are electrically integrated with PG&E.

was the completion of arrangements by the Company to purchase the approximately 50,000-kilowatt output of a new biomass-fueled generating plant, located in Madera County about 150 miles southeast of San Francisco. The plant, to be owned and operated by California Power & Light Corporation will use pelletized agricultural waste products as fuel. Bechtel Power Corporation is engineering the project and will be the constructor if it is approved by the CPUC.



Wind turbines bring a new mode of generation to the PG&E system. An expanding family of wind projects illustrate the Company's emphasis on alternate energy sources.

Company To Replace PCB Toxic Chemicals

The Company in 1981 continued its systemwide program to reduce potential public health hazards from PCB (polychlorinated biphenyls). This oil-like chemical, because of its coolant, insulating, and fire-resistant characteristics, has been used since the 1930s in capacitors and other equipment in electric distribution systems, substations, and other applications.

More than 2,700 banks of capacitors containing PCB were replaced with non-PCB capacitors.

In addition, PG&E has tested liquid samples throughout its gas system to determine the presence of any PCB. Only a small amount of the liquids have been contaminated to the extent that government regulations called for special handling.

Restrictions Lifted On Power Plant Gas; Oil Requirements Cut

Congress in July acted to permit the continued use of natural gas in existing power plants—a move that will reduce the Company's future consumption of foreign oil.

Repeal of a section of the Fuel Use Act resulted, in part, from endorsements by PG&E, other California utilities, and government bodies throughout the state.

Even before Congress acted, the increased availability of natural gas to generate electricity, plus heightened energy conservation by customers, allowed the Company to cut its fuel oil purchases.

This led, also, to renegotiation and an agreement with Chevron U. S. A.—PG&E's largest supplier—to reduce by more than half the amount of low-sulfur oil the Company will be obligated to buy through 1989.

Renegotiation of contracts with other suppliers also reduced oil purchases during the year as annual requirements dropped to about 10 million barrels, down from a high of nearly 36 million barrels in 1977.

Coal Project Shelved; Utah Mine Sold

Although not excluding coal-fired power plants from its long-term plans, the Company in 1981 withdrew from the proposed $5 billion Allen-Warner Valley electric generating project in Nevada and Utah, and put its 11,360-acre, 250 million-ton coal properties in Utah up for sale.

Sale of the properties purchased in 1976 and 1979 as a source of fuel for the now-deferred Montezuma Power Project northeast of San Francisco is expected to be completed early in 1982.

Withdrawal from the Allen-Warner Valley project came after lower forecasts of growth in electric use and the uncertainty associated with project approval by state and federal agencies.

Gas Operations

PG&E Asks Extension Of Export Permits For Canadian Gas

To maintain Canadian natural gas as a dependable major source of supply, PG&E's subsidiary, Alberta and Southern Gas Co. Ltd., in August applied for an extension of its four export licenses at currently authorized levels through October 1993. Omnibus hearings on Alberta and Southern's application and a number of other export requests of other companies will be conducted by the National Energy Board of Canada during the spring and summer of 1982.

Earlier in the year, contracts under which the Company receives gas from Canada were modified. This permits PG&E to reduce, through June of 1982, purchases of Canadian gas, presently the Company's highest cost gas supply, and to purchase additional gas from lower-cost domestic sources.

This reduction in Canadian gas purchases also lessened the impact on customers of a 47 cent price increase (from $4.47 to $4.94 per million British thermal units) which the Canadian government imposed in early 1981.

Company Now Receiving More Lower-Cost Gas From California Wells

Purchases of gas from fields in California increased approximately 30 percent in 1981, bringing additional supplies of this lower-cost gas to customers and for use in the Company's own thermal power plants.

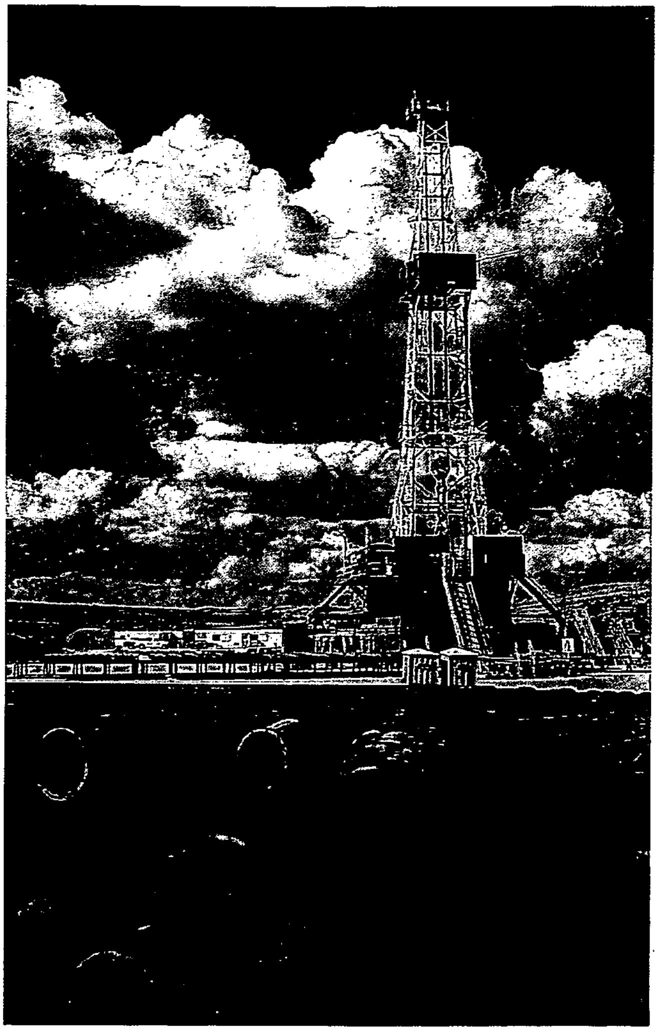
For many years, the availability of ample supplies of Canadian and Southwest gas caused PG&E to adopt a purchase policy to conserve in-state natural gas in order to prolong the life of California gas reserves and, in addition, to meet peak demands in winter without building additional, expensive gas storage facilities.

However, this policy has been modified, and the Company now purchases California supplies in increased volumes because of its lower price.

Subsidiary Expands Gas Exploration In Rockies, California

The continuing increase in the cost of all of the Company's major existing supply sources and the projected long-term decline in these supplies have prompted the Company's wholly-owned subsidiary, Natural Gas Corporation of California (NGC) to take an active part in exploring for gas in California and in the Rocky Mountain area.

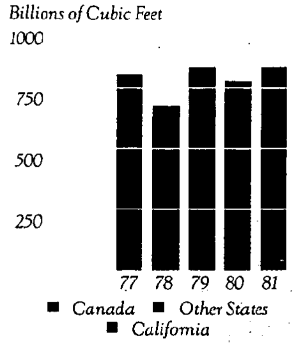
Approximately $76 million was expended by NGC in 1981 for gas exploration and development in both the Rockies and California, principally under the Gas Exploration and Development Adjustment (GEDA) rate procedure authorized by the CPUC.



Probing more than 18,000 feet through a high Wyoming plateau, a modern, highly automated drilling rig operated by PG&E's subsidiary, Natural Gas Corporation of California, searches for still another new source of gas supply for the parent company.

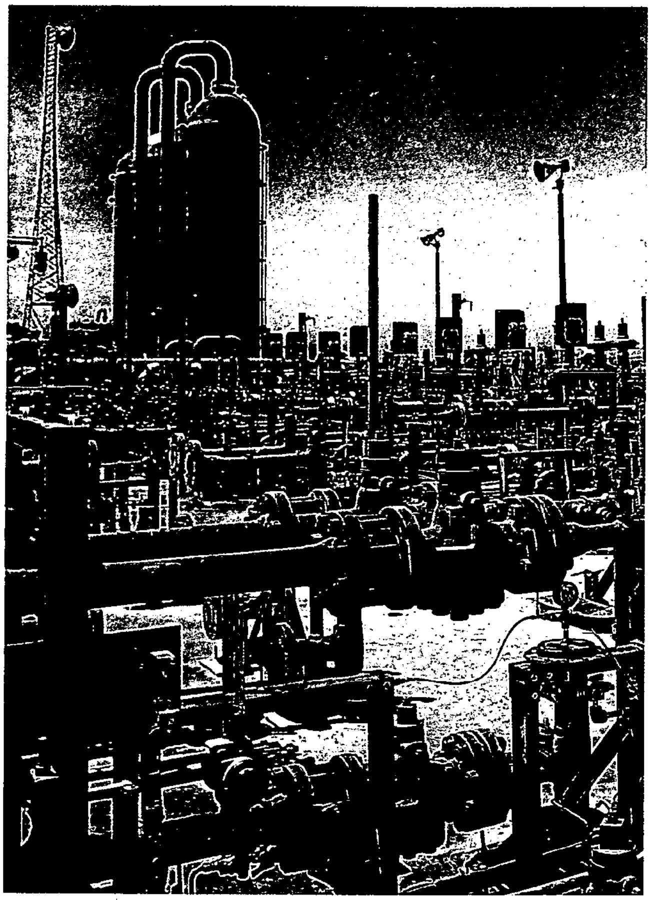
Here in the Rocky Mountain area, the much-publicized Overthrust Belt—formed by continental drift eons ago—contains potentially large quantities of oil and gas.

Sources of Natural Gas



Under this procedure, PG&E's gas customers pay the carrying costs and amortization of funds advanced by PG&E for exploration and development as well as related administrative and general costs. The benefits of successful GEDA projects are flowed back to the Company's customers in the form of lower gas prices.

During 1981, NGC participated in drilling 90 wells, up from 61 in 1980 and 58 in 1979.



At PG&E's underground gas storage field at McDonald Island in the San Joaquin Delta, shown above, and at two other fields near Concord and Winters, approximately 100 billion cubic feet of gas can be stored to provide a ready supply to help meet winter peak demands.

Gas from exploration and development projects conducted by NGC in the Rocky Mountain area is now being delivered to the Company at the rate of about 35 million cubic feet a day through the pipelines of other companies.

Our Pacific Gas Transmission Company (PGT) subsidiary, in partnership with El Paso Natural Gas Company, Northwest Pipeline Corporation and Pacific Interstate Transmission Company, is planning a 583-mile pipeline which eventually could bring up to 800 million cubic feet a day of Rocky Mountain gas into California.

While the GEDA procedure was extended during 1981 for another four years, the Commission ordered that investments in new California and Rocky Mountain exploration projects be 20 percent funded by PG&E stockholders and we are proceeding on this basis.

Outlook Improves For Alaska Gas Pipeline

Congress and the Administration acted in December to remove certain obstacles to the private financing and construction of the Alaska Highway Pipeline Project that, by the latter part of this decade, could bring 230 million cubic feet a day of natural gas to the Company from the North Slope of Alaska—an amount equal to almost ten percent of PG&E's current gas supply.

The project will be the largest private construction job in history. This 4,800-mile pipeline will extend from Prudhoe Bay on the Alaskan North Slope, through Canada, to the lower-48 states, with eastern and western delivery legs ending, respectively, in Illinois and California.

Through a wholly owned subsidiary, the Company is in partnership with other gas companies to build the Alaskan portion of the project. The December action by the Congress and Administration removed earlier restrictions that prevented North Slope oil and gas producers from participating in the financing and construction of the Alaskan segment.

The Company and its PGT subsidiary will construct and operate the United States portion of the western leg by expanding existing pipeline facilities which now run from the Canadian border into California.

A "pre-build" section of the western leg portion, built by PGT, became operational in October 1981.

The PGT "pre-build" section is used in conjunction with pipeline facilities of Northwest Pipeline Corporation and El Paso Natural Gas Company to transmit new Canadian gas, pursuant to a seven year export license, to Southern California Gas Company customers.

Favorable Findings On LNG Receiving Terminal

The Company's joint venture to import 900 million cubic feet a day of liquefied natural gas (LNG) from Alaska and Indonesia gained additional ground in 1981.

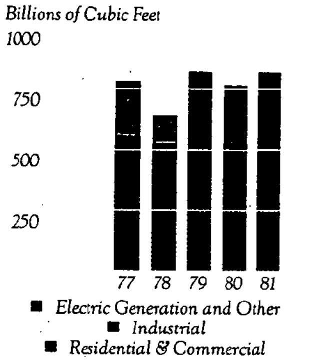
In November, a seismic review panel of engineers and geologists appointed by the California Public Utilities Commission found the proposed LNG receiving terminal on the north coast of Santa Barbara County near Point Conception could safely withstand earthquakes. Earlier in 1981, the CPUC determined that wind and sea conditions were compatible with operational plans for the tankers required for delivery of LNG at the Point Conception site.

In January 1982 the CPUC and Federal Energy Regulatory Commission began a joint public hearing on the seismic panel report. It is hoped that final approvals for the terminal site will be issued by mid-1982.

Agreement was reached with Indonesia for an additional one-year contract extension to accommodate project delays. The extension allows for purchase of newly discovered gas, since the gas originally earmarked for the U. S. has been sold to Japan.

Escalating costs of the projects due to inflation and regulatory delays have made it necessary for the Company and Pacific Lighting Corporation to seek other partners to finance them.

Uses of Natural Gas



The Company continues to view LNG as an important long-term gas supply which could enhance the reliability, security and availability of natural gas to this State in the 1990's and beyond.

Coal Gasification Plan Put On Hold

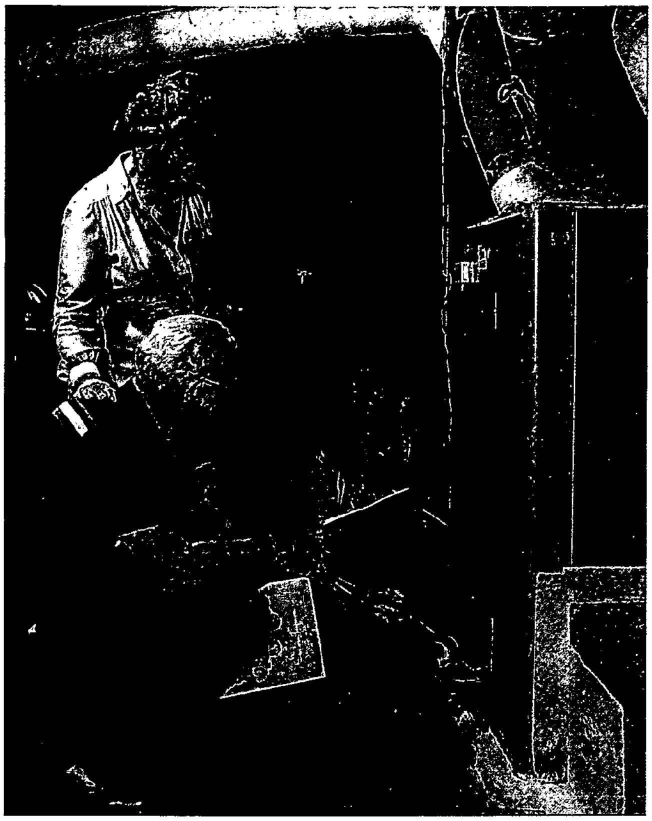
Because chances of obtaining a $1.78 billion federal loan guarantee from the Synthetic Fuels Corporation appeared doubtful, PG&E and two cosponsors in August deferred indefinitely plans to build the nation's largest coal gasification plant near Douglas, Wyoming.

WyCoalGas, Inc., a subsidiary of Panhandle Eastern Corporation, along with Ruhrgas, A. G., a West German company, and PG&E decided that no further investment in the project could be justified beyond the $16.5 million already spent.

Conservation

Conservation Programs At Record High Level

Customers, more than ever during 1981, helped provide additional energy supplies for the PG&E service area by limiting and managing their use of gas and electricity.



PG&E is aggressively selling energy conservation to its customers. During 1981 Company representatives conducted more than 53,000 home energy audits, like the one shown above. This free service, which can lead to recommending insulation and other weatherization, can cut energy waste and save as much as 25 percent of the cost of space and water heating.

PG&E-sponsored activities ranged from responding to nearly 200,000 toll-free telephone inquiries at its Energy Conservation Center in San Francisco to more than 100,000 personal visits with every type of customer to assist them in finding ways to conserve.

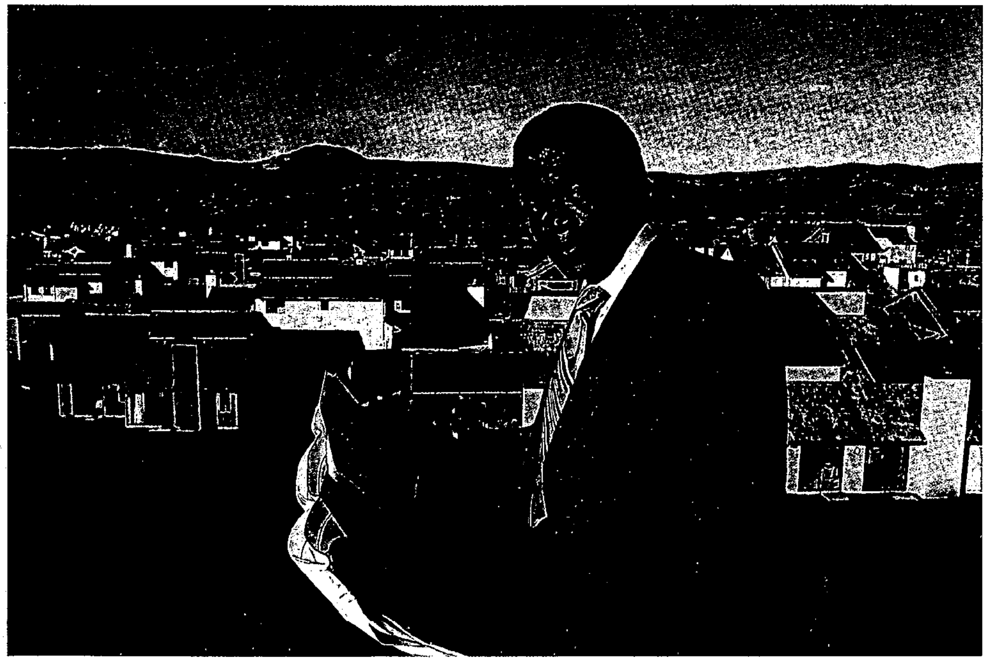
For "leading the country in utility-sponsored conservation programs," the Company received the Corporate Energy Management Award from the Association of Energy Engineers, adding this to a similar White House award received earlier in 1981.

The Company during 1981 provided more than 53,000 free home energy audits to customers, often recommending insulation, weatherstripping, solar water heating, and other measures to cut energy use.

At year's end, PG&E had promoted or sponsored more than 50 community conservation programs, such as energy fairs, exhibits, forums, and special programs conducted by cities and counties.

A Company training facility in Stockton was tripled in size and its programs expanded. The center was opened in 1978 to teach workers from community action agencies and local governments to weatherize homes of low-income, elderly, and disabled persons.

The center, which has set a pattern for others across the nation, trained more than 900 students—many of them learning to make home repairs and to conduct home energy audits. The Company also trains many of its own conservation specialists at the center.



PG&E energy conservation specialists during 1981 reviewed more than 200 projects where newly built homes use solar energy and adopt the Company's residential insulation/weatherization standards. PG&E honors such builders for their energy-saving approach to new construction.

PG&E conservation education programs and demonstrations reached an estimated 12.5 million people during the year through appearances at schools, universities, youth organizations, civic organizations, clubs and church groups.

The Company also contributed to energy conservation through 45 research and development projects, including pilot programs to recover gas from organic waste (biomass) and from garbage at sanitary landfills.

PG&E during the year helped commercial, industrial, and agricultural customers find ways to reduce energy use in their operations through more than 20,000 on-site analyses of buildings and equipment. The Company also continued to make its own facilities more energy-efficient.

PG&E replaced more than 55,000 mercury and incandescent street lights with high-pressure sodium vapor lights during 1981 resulting in significant energy savings for its municipal customers.

All of these conservation efforts combined to save an estimated 384 million kilowatthours of electricity and 60 million therms of natural gas in 1981 (a combined equivalent of 1.6 million barrels of oil) at roughly one-tenth the cost of new conventional energy supplies.

The Company's expenditures on its conservation and loan management programs are budgeted separately from other expenditures and are covered expressly in rates established for the Company by the California Public Utilities Commission.

Research and Development

Solar Research Among Projects To Develop New Energy Sources

Research designed to keep PG&E in the forefront of new technologies that can make its electric and gas operations more efficient continued in five major areas during 1981.

These were: investigations into new sources of energy production and transmission; emerging energy supply technologies; conservation and load management; environmental quality; and general research, including industry-funded programs.

Among the projects centered at the Company's Engineering Research Laboratory at San Ramon was the testing of solar photovoltaic cells, which convert sunlight directly into electricity.

Under an agreement with Westinghouse Electric Corporation, the program is designed to lower the cost of solar cells to a level where they could be major, economical generators of electric power.

In other areas, PG&E and General Electric Company are working on a marriage of coal and fuel cells for a power plant. PG&E is handling the design of the plant.

The coal would be converted into a gas and scrubbed clean of pollutants. The clean gas, when it reacts with oxygen in the fuel cell, would produce electricity. Unlike ordinary combustion, the chemical reaction creates no new pollutants.

If it works as expected, the coal-gas fuel cell combined cycle plant would operate with very low emissions and boast an efficiency nearly double that of cleaned up versions of today's most efficient coal-fired power plants.

The increasingly strong demand in the years ahead for water conservation has involved the Company in research to test advanced power plant concepts that could reduce the cooling water needed by thermal power plants by 75 percent.

As part of this water-conservation research, a three-year dry cooling tower demonstration, sponsored by the Electric Power Research Institute, is under way at PG&E's Kern Power Plant, near Bakersfield.

Communications

Operating Efficiencies Linked To PG&E's Own Communications Network

Like a huge spiderweb, PG&E's communication network of wire and microwave channels, links more than 1,300 locations—power plants, substations, service centers, offices, and other gas and electric facilities spread across a 48-county area of California.

This communication system has grown and been modernized step-by-step with the Company since its early beginnings. Power system dispatchers more than 85 years ago depended on the reliability of PG&E's own telephone lines to control power from remote, often snowbound, hydro plants on slopes of the Sierra.

Today, the heart of this Company nerve system is a modern, cost-effective microwave system extending 4,000 route miles. Overall multiple voice and data circuits cover more than 300,000 miles.

Operating efficiencies, indeed, are linked to PG&E's own communications network. Here, a technician gives giant reflectors "thousandth-of-an-inch" adjustments as they bend a 300-channel microwave over a mountain. Reflector, at left, receives signals beamed 50 miles eastward from Fresno. Signals then bounce to the other reflector, and downward to the Helms Pumped Storage Hydroelectric Project on the Kings River.

Our Employees

Personnel Resources Strive to Meet Productivity Goals

The Company gives continuing attention to organizing its personnel resources to meet new standards of quality and productivity.

PG&E repair crews worked around the clock to restore service to more than one million customers when wind and rain from monster winter storms in November and again in January 1982 battered the Company's gas and electric system.

During 1981, a comprehensive succession and manpower planning system for filling future vacancies in management positions was put into effect.

This new system is designed to ensure that an adequate number of management employees develop appropriate skills and obtain the experience necessary to meet management staffing needs in the years ahead.

In another area, more than 1,500 employees, who deal directly with customers, attended skill improvement seminars and received technical training.

Improved job scheduling and more efficient use of equipment and personnel came from an improved work review program.

The Company's 60-year-old Employee Suggestion System in 1981 produced 4,168 ideas and lowered the Company's costs during the year by about $3 million.

Scaling back construction and other activities in accordance with the changing nature of the Company's work brought a net reduction in employment of about 1,000 in 1981, leaving 26,625 in the work force at year's end.

Minority employees comprise about 25 percent of the Company's work force. This corresponds closely to the percentage of minorities of working age in the PG&E service area.

The Company's personnel management system provides ever-expanding opportunities for women to develop and advance as their skills, interests, and productivity permit.

More than 5,000 women make up about 18 percent of the Company's work force. Women fill 11 percent of salaried positions.

Many now hold managerial positions in a wide range of functions such as accounting, computer operations, customer services, district office management, law, engineering, and personnel management.

About 860 women work in so-called nontraditional, physical jobs, an increase of nearly 15 percent in one year.

About 17,200 employees are represented by the International Brotherhood of Electrical Workers (AFL-CIO) and 1,770 by the Engineers and Scientists of California.

During 1981, 564 employees marked 25 years of service with the Company, bringing total membership in PG&E's Quarter Century Club to 4,900.

Executive Changes

New Directors Serving on Board

Membership changes on the Board of Directors included the addition of Peter A. Magowan, chairman of the board and chief executive officer of Safeway Stores, Inc., and John B. M. Place, chairman of the board and chief executive officer of Crocker National Bank.

Mr. Magowan replaced Myron Du Bain, chairman and president of Fireman's Fund Insurance Companies, who in September 1981 resigned following a merger of Fireman's Fund's parent, American Express Company, with Shearson Loeb Rhoades, Inc., stockbrokers and underwriters.

A provision of the Federal Power Act prohibits simultaneous service on the boards of utilities and firms authorized to underwrite and market securities.

Mr. Place, who had served as an advisory director since December 1981, was elected in February 1982 to replace Emmett G. Solomon, who retired under the PG&E board of directors' age-in-service policy.

At the same time, Harry M. Conger, Chairman of the Board, President and Chief Executive Officer of Homestake Mining Company, was appointed an Advisory Director.

PG&E's nine-member Management Committee completed its first full year of operation and is providing the strong, efficient leadership intended under this new executive structure.

Gary E. Lavering, assistant treasurer, was elected vice president and comptroller, succeeding Frank A. Peter, who retired in December after 11 years in that position.

Earlier, Mr. Lavering served as treasurer or assistant treasurer of PG&E subsidiaries, as well as manager of banking and money management and budget development coordinator for the parent company.

Donald C. Albright, a 35-year veteran of the Company's electric operations, was named manager of PG&E's Humboldt Division in December, succeeding Roy C. Atkins, who retired after a 40-year career with the Company.

Selected Financial Information

The following table displays data which is discussed in the Management's Discussion and Analysis of Consolidated Financial Condition and Results of Operations.

	1981	1980	1979	1978	1977
	In Thousands (except percentage and per share information)				
Results of Operations:					
Operating Revenues	**$ 6,194,575**	$ 5,258,899	$ 4,364,469	$3,569,373	$3,629,530
Operating Income	**$ 647,209**	$ 573,147	$ 515,903	$ 468,088	$ 459,432
Net Income	**$ 564,606**	$ 524,770	$ 458,234	$ 400,451	$ 355,677
Earnings Per Common Share	**$3.41**	$3.60	$3.55	$3.18	$3.14
Dividends Declared Per Common Share	**$2.72**	$2.60	$2.38	$2.16	$2.00
Dividend Payout Ratio	**79.8%**	72.2%	67.0%	67.9%	63.7%
Return on Common Stock Equity*	**11.3%**	11.7%	11.5%	11.0%	10.7%
Return on Utility Investment					
Earned	**8.8%**	8.6%	8.5%	8.1%	8.3%
Authorized	**10.3%**	10.3%	9.5%	9.5%	9.2%
Liquidity:					
Total Assets at Year End	**$12,366,659**	$11,295,203	$10,310,763	$8,665,160	$8,216,285
Ratio of Construction Work in Progress to Net Utility Plant at Year End	**34.4%**	33.9%	31.2%	27.3%	24.6%
Net Short-term Borrowings at Year End	**$ 913,271**	$ 634,974	$ 561,910	$ 69,141	$ 121,724
Regulatory Balancing Accounts Receivable at Year End	**$ 303,416**	$ 325,360	$ 622,142	$ 98,540	$ 220,796
Capital Resources:					
Construction Expenditures	**$ 1,383,714**	$ 1,221,758	$ 1,149,308	$ 859,113	$ 721,324
Financing — Net Proceeds					
Long-term Debt	**$ 522,511**	$ 497,834	$ 372,404	$ 249,567	$ 198,393
Preferred Stock	**131,541**	132,306	149,383	132,429	106,223
Common Stock	**122,114**	236,746	276,564	58,758	225,638
Sale of Nuclear Fuel	**245,393**	—	—	—	—
Total Financing	**$ 1,021,559**	$ 866,886	$ 798,351	$ 440,754	$ 530,254
Long-term Debt and Preferred Stock at Year End	**$ 5,849,705**	$ 5,464,531	$ 4,940,013	$4,560,083	$4,329,131
Book Value Per Common Share at Year End*	**$30.29**	$29.94	$29.66	$29.50	$28.52
Market Price Per Common Share at Year End	**$21**	$20½	$23	$22¼	$24

*Restated — see note 1 to consolidated financial statements

Management's Discussion and Analysis of Consolidated Financial Condition and Results of Operations

Overview

In recent years the Company has fallen far short of earning its authorized rate of return principally because customer rates were inadequate to recover the costs of providing service. As a result, the Company has suffered a continuing deterioration in its financial condition. This was evidenced by the downgrading of the Company's securities in early 1982 by two rating agencies, while a third is currently reviewing its rating of the Company's securities.

A reversal of this financial trend is expected. As emphasized in the Letter to Stockholders, restoration of financial health is a key corporate goal. The actions in furtherance of this goal should have favorable impacts on results of operations, liquidity and capital resources.

Of the various actions planned to improve the Company's financial condition, the commitment to operate within revenue and expense levels provided by rate case decisions has immediate importance in view of a general rate decision by the California Public Utilities Commission (CPUC) on December 30, 1981. That decision granted an increase of $656 million in nonfuel-related general electric and gas rates, and an additional $177 million for the effects of income tax normalization as required by the Economic Recovery Tax Act of 1981. The CPUC also increased the authorized return on common equity to 16%, and established two new mechanisms which should improve the Company's ability to earn that return.

The first of these is the Electric Revenue Adjustment Mechanism (ERAM). The purpose of ERAM is to eliminate the impact on earnings of electric sales fluctuations due to conservation, weather conditions or other causes. This assures that the utility will collect the authorized amount of revenues as estimated by the CPUC in granting the general rate increase. Therefore, differences in actual sales volumes and revenues from estimates used by the CPUC in establishing both electric and gas rates will be automatically adjusted through ERAM and a similar balancing account mechanism already in operation for gas sales.

The other mechanism established was the Attrition Rate Adjustment (ARA). The purpose of the ARA provision is to adjust rates in 1983 to recover expense increases caused by inflation and growth. Labor and certain nonlabor expenses used in establishing 1983 rates will be based upon 1982 expenses indexed for inflation.

Results of Operations

Although 1981 operating revenues increased $936 million from the prior year, customer rates were inadequate to recover the costs of providing service, and net income increased only $40 million. This $40 million increase was more than offset by additional preferred dividend requirements and more common shares outstanding. The result was a decrease in earnings per share of 19 cents from the prior year to $3.41 per share, which is equivalent to an 11.3% return on consolidated common stock equity.

The Company has in recent years experienced a significant difference between the returns earned on consolidated common stock equity and the returns authorized by regulatory bodies. Some of the detrimental effects of inflation have been lessened by actions of the CPUC which has established energy-cost balancing accounts, more timely action on general rate increases, and increases in authorized rates of return. The following table shows the major categories of changes in revenues from the preceding year.

For the Years Ended December 31,	**1981**	1980	1979	1978	1977
	In Millions				
Electric Revenues					
Rate Changes					
General	**$ 109.9**	$ 88.2	$ 4.2	$ 67.0	$ 88.7
Energy	**252.2**	891.5	(354.4)	21.8	630.7
Sales Volume and Other Changes	**187.6**	(31.0)	147.4	(28.6)	53.9
Balancing Account Revenue Increases	**428.3**		569.7		
Balancing Account Revenue Decreases		(484.7)		(318.4)	(239.1)
Net Increase (Decrease)	**$ 978.0**	$ 464.0	$ 366.9	$(258.2)	$ 534.2
Gas Revenues					
Rate Changes					
General	**$ 25.5**	$ 68.0	$ 106.2	$ 22.8	$ 28.8
Gas Purchased	**120.4**	767.9	183.0	54.6	138.6
Sales Volume and Other Changes	**(45.3)**	(95.3)	156.6	(92.8)	(65.5)
Balancing Account Revenue Increases				213.4	
Balancing Account Revenue Decreases	**(142.9)**	(310.2)	(17.6)		(55.1)
Net Increase (Decrease)	**$ (42.3)**	$ 430.4	$ 428.2	$ 198.0	$ 46.8

Rate changes include those changes which occurred during the year at various times. The decline in gas volumes resulted principally from conservation due to PG&E sponsored awareness programs, CPUC mandated programs, and price increases. The sales volume of electric energy increased primarily due to an increase in the number of customers and increased usage in all areas except residential.

Energy-cost balancing accounts accumulate the difference between actual energy costs incurred and actual energy revenues billed to recover such costs. The operation of the energy-cost balancing accounts enables the Company to recover the majority of fuel-related costs as well as to compensate for fluctuations in gas and electricity usage. However, because of inflation, the actual costs of labor, materials and financing costs which includes interest and preferred stock dividends, far exceeded estimates of such costs used by the CPUC in fixing the Company's rates for 1981.

Liquidity

Allowance for equity and borrowed funds used during construction (AFUDC) has increased greatly in recent years as the result of higher costs of funds and the increasing investment in construction work in progress (CWIP). Annual rates for AFUDC were 8.8% in 1981, 8.7% in 1980, and 8.1% in 1979.

The ratio of CWIP to net utility plant is an important indicator of the Company's liquidity. Although AFUDC is included in net income, it does not represent current cash income. Only when construction is included in utility rate base can it contribute to the Company's cash flow. On the other hand, construction expenditures do require current cash expenditures, both for the construction itself and for the cost of money used for the investment in CWIP. As the ratio of CWIP to net utility plant increases, it becomes more difficult to generate the cash needed for additional construction.

Because of the large size of the Diablo Canyon nuclear power and Helms pumped storage projects still under construction, the amount of CWIP relative to net utility plant has grown as these projects have neared completion. The Diablo nuclear units are substantially complete and awaiting operating licenses. Total investment in Diablo's two nuclear units at December 31, 1981 was $2.2 billion including $821 million of AFUDC. The Helms pumped storage project is well over 78% complete and at December 31, 1981 had accumulated costs of $593 million including $101 million of AFUDC. The CPUC has indicated that it intends to treat large projects such as the Diablo nuclear units and Helms pumped storage as special offset rate cases when they become operational. Under this procedure the Company expects that general rates will be increased to recover the cost of depreciation, return on investment, and operating expenses while energy rates will be reduced because of the lower costs of power from nuclear and pumped storage units. Since AFUDC for these projects will be discontinued, there should be little, if any, effect on the Company's earnings, but cash flow will be greatly improved and the ratio of CWIP to net utility plant will be greatly reduced.

One of the major financial trends in the last five years has been the increase in the use of short-term debt relative to capitalization. The Company's policy is to use short-term debt (primarily commercial paper) to finance the unrecovered balances in balancing accounts, and for interim financing of its construction program. The Company maintains bank lines of credit sufficient to support sales of commercial paper.

Capital Resources

It is estimated that consolidated construction expenditures during 1982 will approximate $1.4 billion. Construction expenditures will continue to be funded primarily through external financings.

The cost of the Company's investment in energy supply projects has increased greatly because of regulatory and environmental considerations, inflation, and a greater difficulty in obtaining new sources of energy. In addition, these projects are under construction for longer periods than in the past. This situation increases the risk the Company may have of not recovering its entire investment in projects not carried to a successful conclusion. There is no reasonable way to estimate which projects or costs, if any, may be disallowed; however, the Company would pursue vigorously any avenue available to it for arguing against disallowance of legitimate costs incurred by the Company in carrying out its mandate to serve the public.

As part of the plan to improve its financial condition, the Company will minimize capital expenditures and avoid major commitments of capital to new energy supply projects. It will pursue this policy until it is able to achieve and maintain a financial condition adequate to support a quality, double-A debt rating and a common stock market price in excess of book value.

Consolidated Statements of Income

For the Years Ended December 31,	1981	1980	1979
	In Thousands (except per share amounts)		
Operating Revenues			
Electric	$3,905,873	$2,927,841	$2,463,845
Gas	2,288,702	2,331,058	1,900,624
Total Operating Revenues	6,194,575	5,258,899	4,364,469
Operating Expenses			
Operation			
Cost of Electric Energy	2,123,484	1,465,680	1,231,169
Cost of Gas Sold	1,870,731	1,833,831	1,405,516
Transmission	115,977	105,594	102,999
Distribution	135,828	122,720	110,227
Customer Accounts and Services	180,022	150,282	122,413
Administrative and General	316,935	275,714	226,016
Other	70,534	63,426	49,161
Total Operation	4,813,511	4,017,247	3,247,501
Maintenance	181,508	157,262	132,577
Depreciation	303,479	280,710	250,864
Gas Exploration	19,135	13,213	13,050
Taxes on Income	124,216	123,698	100,071
Property and Other Taxes	105,517	93,622	104,503
Total Operating Expenses	5,547,366	4,685,752	3,848,566
Operating Income	647,209	573,147	515,903
Other Income and Income Deductions			
Allowance for Equity Funds Used During Construction	225,550	202,873	159,669
Interest Income	81,661	96,442	36,016
Minority Interest in Net Income of Subsidiary Companies	(15,826)	(4,991)	(3,934)
Other — Net	61,814	41,422	21,500
Total Other Income and Income Deductions	353,199	335,746	213,251
Income Before Interest Charges	1,000,408	908,893	729,154
Interest Charges			
Interest on Long-term Debt	376,927	322,344	279,912
Interest on Short-term Debt	118,293	112,609	26,137
Less Allowance for Borrowed Funds Used During Construction	(59,418)	(50,830)	(35,129)
Total Interest Charges	435,802	384,123	270,920
Net Income	564,606	524,770	458,234
Preferred Dividend Requirements	133,699	109,169	92,291
Earnings Available for Common	$ 430,907	$ 415,601	$ 365,943
Average Common Shares Outstanding	126,551	115,600	103,225
Earnings Per Common Share	$3.41	$3.60	$3.55
Dividends Declared Per Common Share	$2.72	$2.60	$2.38

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Balance Sheets

December 31,	1981	1980
	In Thousands	
Assets		
Utility Plant (at original cost)		
Electric	$ 7,234,714	$ 6,804,267
Gas	2,481,967	2,219,386
Construction Work in Progress	3,370,922	3,078,485
Total Utility Plant	13,087,603	12,102,138
Accumulated Depreciation	3,294,495	3,031,467
Utility Plant – Net	9,793,108	9,070,671
Gas Exploration Costs	217,322	132,094
Advances to Gas Producers	183,769	144,190
Construction Funds Held by Trustee	46,803	–
Investment in LNG Partnerships	175,744	145,559
Investment in Alaska Natural Gas Transportation System	43,462	33,383
Investment in Alberta Natural Gas Company Ltd	34,145	21,409
Other Investments	3,709	2,277
Current Assets		
Cash	1,827	1,715
Short-term Investments (at cost which approximates market)	15,393	66,242
Accounts Receivable		
Customers	537,603	489,885
Other	121,988	79,185
Total Accounts Receivable	659,591	569,070
Less Allowance for Uncollectible Accounts	6,915	5,872
Accounts Receivable – Net	652,676	563,198
Regulatory Balancing Accounts – Receivable	303,416	325,360
Inventories (at average cost)		
Fuel Oil	484,595	453,885
Gas Stored Underground	255,169	202,887
Materials and Supplies	109,820	96,902
Total Inventories	849,584	753,674
Prepayments	8,133	12,022
Total Current Assets	1,831,029	1,722,211
Deferred Charges		
Unamortized Bond Expense	9,317	4,929
Other – Net	28,251	18,480
Total Deferred Charges	37,568	23,409
Total Assets	$12,366,659	$11,295,203

The accompanying notes to consolidated financial statements are an integral part of these statements.

December 31,	1981	1980
	In Thousands	
Capitalization and Liabilities		
Capitalization		
Common Stock (authorized 200,000,000 shares, par value $10 per share; issued and outstanding at December 31: 1981 – 129,552,419; 1980 – 123,849,412)	$ 1,295,524	$ 1,238,494
Additional Paid-in Capital	1,003,151	931,526
Reinvested Earnings (Restated – Note 1)	1,625,996	1,537,450
Common Stock Equity	3,924,671	3,707,470
Preferred Stock Without Mandatory Redemption Provision	1,352,451	1,227,451
Preferred Stock With Mandatory Redemption Provision	150,000	150,000
Long-term Debt	4,347,254	4,087,080
Total Capitalization	9,774,376	9,172,001
Current Liabilities		
Short-term Borrowings	928,664	710,216
Accounts Payable – Trade Creditors	483,959	452,711
Accounts Payable – Other	153,850	105,979
Accrued Taxes	127,860	244,935
Interest Payable	45,277	29,820
Dividends Payable	88,021	76,448
Customer Deposits	16,471	15,568
Long-term Debt – Current Portion	227,776	10,364
Refunds Due Customers	13,290	25,889
Other	71,464	62,391
Total Current Liabilities	2,156,632	1,734,321
Deferred Credits		
Customer Advances for Construction	92,455	90,667
Deferred Investment Tax Credits	27,411	36,187
Deferred Income Taxes of Subsidiaries	85,609	49,007
Deferred Income Taxes on Defense Facilities	22,757	25,703
Unamortized Gain on Reacquired Debt	102,059	88,743
Other	32,162	36,476
Total Deferred Credits	362,453	326,783
Minority Interest in Subsidiary Companies	73,198	62,098
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$12,366,659	$11,295,203

Consolidated Statements of Funds Used for Construction

For the Years Ended December 31,	1981	1980*	1979*
	In Thousands		
Funds From Operations			
Net Income	$ 564,606	$ 524,770	$ 458,234
Nonfund Items in Net Income			
Depreciation (including charges to other accounts)	308,014	284,634	254,068
Allowance for Equity Funds Used During Construction	(225,550)	(202,873)	(159,669)
Other – Net	24,512	8,354	23,570
Regulatory Balancing Accounts	21,944	296,782	(523,602)
Funds From Operations	693,526	911,667	52,601
Funds From Financing			
Common Stock Sold	122,114	209,296	276,564
Common Stock Sold by Subsidiary Company	—	27,450	—
Preferred Stock Sold	131,541	132,306	149,383
Long-term Debt Sold	569,314	497,834	372,404
Construction Funds Held by Trustee	(46,803)	—	—
Sale of Nuclear Fuel	245,393	—	—
Net Short-term Borrowings	269,297	82,064	472,939
Funds From Financing	1,290,856	948,950	1,271,290
Other Changes in Working Capital(a)	(67,320)	(52,930)	179,963
Other — Net	(113,449)	5,679	27,825
Total Funds Provided	1,803,613	1,813,366	1,531,679
Funds Used for Other Than Construction			
Long-term Debt Matured	(38,902)	(51,482)	(100,628)
Long-term Debt Purchased for Sinking Fund (at cost)	(47,495)	(51,997)	(43,680)
Dividends on Preferred and Common Stock	(476,060)	(408,099)	(340,358)
Fuel Oil Inventory	(30,710)	(246,568)	(52,912)
Gas Stored Underground	(52,282)	(36,335)	(4,462)
Total Funds Used for Other Than Construction	(645,449)	(794,481)	(542,040)
Funds Used for Construction	1,158,164	1,018,885	989,639
Allowance for Equity Funds Used During Construction	225,550	202,873	159,669
Total Construction Expenditures	$1,383,714	$1,221,758	$1,149,308

(a) Other Changes in Working Capital excludes changes in current portion of mortgage bonds due to bonds maturing in one year: 1981, ($172,564); 1980, $30,288; 1979, $15,568.

*Changed to conform to 1981 presentation.

The accompanying notes to consolidated financial statements are an integral part of these statements.

Consolidated Statements of Common Stock Equity and Preferred Stock

For the Years Ended December 31, 1981 1980, and 1979	Common Stock	Additional Paid-in Capital	Reinvested Earnings	Common Stock Equity	Preferred Stock Without Mandatory Redemption Provision	Preferred Stock With Mandatory Redemption Provision
	In Thousands					
Balance, January 1, 1979						
As previously reported	$1,008,793	$ 664,337	$1,322,303	$2,995,433	$1,102,451	$ –
Adjustment to reflect accrual of liability for vacation pay (Note 1)			(19,400)	(19,400)		
Balance as restated	1,008,793	664,337	1,302,903	2,976,033	1,102,451	–
Net Income – for 1979			458,234	458,234		
Preferred Stock Sold (1,500,000 Shares)		(617)		(617)		150,000
Common Stock Sold (12,748,253 Shares)	127,482	149,082		276,564		
Cash Dividends Declared						
Preferred Stock			(90,041)	(90,041)		
Common Stock			(250,317)	(250,317)		
Balance, December 31, 1979	1,136,275	812,802	1,420,779	3,369,856	1,102,451	150,000
Net Income – for 1980			524,770	524,770		
Preferred Stock Sold (5,000,000 Shares)		7,306		7,306	125,000	
Common Stock Sold (10,221,870 Shares)	102,219	107,077		209,296		
Cash Dividends Declared						
Preferred Stock			(106,502)	(106,502)		
Common Stock			(301,597)	(301,597)		
Increase from Capital Transaction of Subsidiary Company		4,341		4,341		
Balance, December 31, 1980	1,238,494	931,526	1,537,450	3,707,470	1,227,451	150,000
Net Income – for 1981			**564,606**	**564,606**		
Preferred Stock Sold (5,000,000 Shares)		**6,541**		**6,541**	**125,000**	
Common Stock Sold (5,703,007 Shares)	**57,030**	**65,084**		**122,114**		
Cash Dividends Declared						
Preferred Stock			**(130,316)**	**(130,316)**		
Common Stock			**(345,744)**	**(345,744)**		
Balance, December 31, 1981	**$1,295,524**	**$1,003,151**	**$1,625,996**	**$3,924,671**	**$1,352,451**	**$150,000**

The accompanying notes to consolidated financial statements are an integral part of these statements.

Notes To Consolidated Financial Statements

For the Years Ended December 31, 1981, 1980 and 1979

Note 1 Summary of Significant Accounting Policies

Accounting Records
The accounting records of Pacific Gas and Electric Company (PG&E) are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the California Public Utilities Commission (CPUC).

Principles of Consolidation
The consolidated financial statements include the accounts of PG&E and its wholly owned and majority owned subsidiaries (the Company) for all periods presented. In consolidation all significant intercompany transactions and accounts have been eliminated.

PG&E's major subsidiaries are Pacific Gas Transmission Company (PGT), which transports and sells natural gas outside California; Pacific Gas and Electric Finance Company N.V. (Finance), which was organized in 1981 in the Netherlands Antilles to borrow funds outside the United States and to lend such funds to PG&E and its subsidiary companies; Alberta and Southern Gas Co. Ltd. (A&S), whose principal functions are the acquisition of gas in Canada and arranging for its transportation to the U.S. border; and Natural Gas Corporation of California (NGC), which is a natural gas exploration and producing company. Subsidiaries of PG&E engaged in projects that are still in the development stages include Eureka Energy Company, formed to engage in the acquisition and development of coal and other energy sources; Calaska Energy Company, a member of the partnership to construct the Alaskan portion of the Alaska Natural Gas Transportation System for the transportation of natural gas from Alaska to the continental United States; and Alaska California LNG Company, Pacific Gas LNG Terminal Company, Pacific Gas Marine Company, and Pacific Indonesia LNG Company, which were formed to engage in the delivery of natural gas by ship to California. Alberta Natural Gas Company Ltd (ANG) is a subsidiary of PGT. ANG owns and operates the pipeline whose principal function is to transport natural gas for A&S through British Columbia to the Canadian-U.S. border. The investments in ANG and Pacific Indonesia LNG Company, which are 50% or less owned subsidiaries, are accounted for in accordance with the equity method of accounting.

Revenues
Revenues consist of billings to customers and changes in regulatory balancing accounts. Billings to customers are included in revenues as meters are read on a cycle basis throughout each month. In accordance with orders of the CPUC, the Company has established regulatory balancing accounts for electric energy costs, gas costs and gas sales. Operating revenues include changes in these regulatory balancing accounts. These changes represent amounts authorized by the CPUC to be recovered from or refunded to customers. The effect of using these regulatory balancing accounts is that changes in costs to the Company of electric energy and gas, and fluctuations in gas sales do not affect the Company's earnings. In 1981, the CPUC modified the regulatory balancing account procedure to provide that only 98% of the electric energy costs are to be accumulated in a balancing account. The remaining 2% is subject to annual rate treatment.

Utility Plant
The costs of additions to utility plant and replacements of retirement units of property are capitalized. Costs include labor, material and similar items and indirect charges for such items as engineering, supervision and transportation. Costs also include allowance for funds used during construction (AFUDC), at rates calculated in conformity with FERC authorizations, for the imputed cost of equity investment and a net after-tax amount for borrowed funds. The equity component of AFUDC is included in other income and the borrowed funds component, net of federal and state income taxes, is recorded as a reduction of interest charges. Costs of depreciable units of plant retired are eliminated from utility plant accounts and such costs plus removal expenses less salvage are charged to accumulated depreciation. Costs of repairing property and replacement of minor items of property are included in the Company's Consolidated Statements of Income as Maintenance.

Depreciation
For financial statement purposes, depreciation of utility plant is computed on a straight-line remaining life basis at rates based on the estimated useful lives of properties. For federal income tax purposes, depreciation is generally computed using the most liberalized methods allowed by the Internal Revenue Code.

Income Taxes
The CPUC requires that deferred taxes not be provided on certain timing differences in connection with depreciation and overhead costs of construction. The CPUC also requires that investment tax credits (ITC) be applied as a reduction of the federal income tax accrual. This reduction, commencing in 1981, is based upon the amount of the credit earned in the year. The amount of ITC for 1980 was based upon a two-year moving average method, while 1979 was based upon a five-year moving average method. Customer rates authorized by the CPUC reflect these requirements. Deferred taxes are related to changes in regulatory balancing accounts, nuclear fuel financing, major construction projects, and gas exploration costs. In PG&E's first general rate decision following the enactment of the Economic Recovery Tax Act of 1981 (ERTA), the CPUC has allowed PG&E to

comply with ERTA by granting normalization of certain income tax benefits. The Company, commencing in 1982, will normalize the tax effects of both Accelerated Cost Recovery System and investment tax credits.

Debt Premium, Discount and Related Expenses
Long-term debt issuance premium or discount and related expenses are amortized over the lives of the issues to which they pertain. The gain or loss on reacquisition of bonds to satisfy sinking fund requirements is amortized over the remaining life of the reacquired issues. The federal income tax on such gain is recognized over the life of the remaining property.

Earnings Per Common Share
Earnings per common share are computed by dividing earnings available for common stock by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding is computed by dividing the aggregate of the number of common shares outstanding at the beginning of each month in the period by the number of months in the period.

Research and Development
Research and development (R&D) costs related to specific construction projects are capitalized as are a portion of general engineering research costs. Total R&D costs incurred during the years 1981, 1980 and 1979 were approximately $64,000,000, $79,000,000 and $76,000,000 respectively, of which $49,000,000, $61,000,000, and $60,000,000 were capitalized as part of the cost of construction projects. Other R&D costs are charged to expense.

Gas Exploration Costs
The majority of gas exploration costs are capitalized under a modified "full cost" method of accounting to reflect cost recovery procedures authorized by the CPUC. Prior to the CPUC decision of August 4, 1981, unsuccessful project costs, current operating costs and the financing costs of the gas exploration program were recovered through gas exploration development balancing account procedures. The success, or lack of success, of the Company's gas exploration program did not affect the Company's income because of the operation of the balancing account. However, subsequent to the decision of August 4, 1981, the CPUC ordered that investments in California and Rocky Mountain leases, acquired after October 1980, be 20% funded by nonratepayer provided equity. Therefore 20% of all profits or losses will be recorded in the Company's Consolidated Statements of Income as Other Income and Income Deductions.

Accrued Vacation Pay
In December 1981, as required by Statement of Financial Accounting Standards No. 43, *Accounting for Compensated Absences*, the Company increased the estimated liability for vacation pay earned in the amount of $19,400,000. As permitted by this Statement, the 1971 financial statements of the Company were restated with common stock equity being decreased by a corresponding amount. Net income for 1971 was reduced by $19,400,000 to $176,508,000 and earnings per common share was reduced by $.32 to $2.47. The balance sheets of years subsequent to 1971 have been restated accordingly.

Foreign Currency Translation
In 1980 and 1979 the financial statements of A&S and the equity in ANG were translated from Canadian dollars into United States dollars in accordance with the pronouncements of the Financial Accounting Standards Board (FASB) in effect for those years. In 1981, the translations were made in accordance with Statement of Financial Accounting Standards No. 52, *Foreign Currency Translation*. The effect on net income of adopting the new standard of translation in 1981 is not material.

Note 2 Preferred Stock

The redeemable preferred stock ($25 par) outstanding, with no mandatory redemption provision, is subject to redemption, in whole or in part, solely at the option of the Company upon payment of the redemption price plus accumulated and unpaid dividends to the date fixed for redemption. The redemption premium per share declines in accordance with terms of the specific issue. The involuntary liquidation preference of the preferred stock is par value ($25) plus accrued dividends.

The redeemable preferred stock ($100 par) outstanding, with a mandatory redemption provision, is subject to redemption through the operation of a sinking fund at the sinking fund redemption price of $100 per share, or at the option of the Company upon payment of the redemption price of $100 per share plus a premium, plus in either event accumulated and unpaid dividends to the date fixed for redemption. The redemption premium per share declines annually. For the purposes of the sinking fund the Company must set aside in cash, annually, commencing with November 15, 1985, and ending on November 15, 2004, an amount sufficient to redeem 75,000 shares at the sinking fund redemption price. This provision is cumulative. There are no redemption requirements for the years 1982 through 1984. The Company has the right, at its option, to redeem at the sinking fund redemption price, on November 15, 1985 and on any November 15 thereafter, not more than 75,000 additional shares. This right is not cumulative. Optional redemptions at the sinking fund redemption price are limited to an aggregate of 562,000 shares. The involuntary liquidation preference of this stock is par value ($100) plus accrued dividends.

On January 28, 1982 the Company issued 3,000,000 shares of 17.38% redeemable preferred stock ($25 par).

Dividends on preferred stock are cumulative. Total preferred stock outstanding at December 31, 1981 was:

	Annual Dividend Per Share	Redemption Price Per Share	Shares Authorized	Shares Issued and Outstanding Included Under "Capitalization" in Balance Sheet	
				Number	Amount
			In Thousands		
Preferred Without Mandatory Redemption Provision Par Value $25 Per Share					
Non-Redeemable					
6%	$1.50		4,212	4,212	$ 105,292
5.50%	1.375		1,173	1,173	29,329
5%	1.25		400	400	10,000
Total Non-Redeemable			5,785	5,785	144,621
Redeemable					
16.24%	4.06	$ 31.55	5,000	5,000	125,000
12.80%	3.20	30.70	5,000	5,000	125,000
10.46%	2.615	30.10	3,500	3,500	87,500
10.28%	2.57	30.00	5,000	5,000	125,000
10.18%	2.545	29.25	4,000	4,000	100,000
9.48%	2.37	29.50	3,000	3,000	75,000
9.30%	2.325	29.80	4,000	4,000	100,000
9.28%	2.32	27.25	707	707	17,674
9%	2.25	28.625	881	881	22,027
8.20%	2.05	29.375	2,000	2,000	50,000
8.16%	2.04	28.875	3,000	3,000	75,000
8%	2.00	29.375	2,000	2,000	50,000
7.84%	1.96	29.00	2,000	2,000	50,000
5%	1.25	26.75	2,861	2,861	71,524
5%—Series A	1.25	26.75	1,750	1,719	42,985
4.80%	1.20	27.25	1,517	1,517	37,934
4.50%	1.125	26.00	1,128	1,128	28,186
4.36%	1.09	25.75	1,000	1,000	25,000
Unclassified in Series	—	—	20,871	—	—
Total Redeemable			69,215	48,313	1,207,830
Total Preferred Stock Without Mandatory Redemption Provision			**75,000**	**54,098**	**$1,352,451**
Preferred With Mandatory Redemption Provision Par Value $100 Per Share					
Redeemable					
9%	$9.00	$100.00	1,500	1,500	$ 150,000
Unclassified in Series		—	8,500	—	—
Total Preferred Stock With Mandatory Redemption Provision			**10,000**	**1,500**	**$ 150,000**

Note 3 Long-term Debt

The First and Refunding Mortgage Bonds of PG&E are issued in series, bear annual interest from 3% to 16.9% and mature from June 1, 1982 to August 1, 2020. Subject to indenture provisions as to earnings coverage and bondable property available for security, additional bonds may be issued up to an outstanding aggregate amount of $5,000,000,000. The Board of Directors of PG&E may from time to time increase the amount authorized. All real properties and substantially all personal properties are subject to the lien of the mortgage.

PG&E's securities representing investments in subsidiaries are pledged as collateral for PG&E bonds. The mortgage bonds of PGT are issued in series, bear annual interest from 5¼% to 8% and mature from 1986 to 1990. All real properties and substantially all personal properties and long-term contracts for gas purchases, gas sales and gas transportation of PGT are subject to the lien of the PGT mortgage. At December 31, 1981, long-term debt of the Company was:

Maturity	3% to 6¼%	6⅝% to 10⅛%	10.7% to 16.9%	Total
	In Thousands			
Pacific Gas and Electric Company				
Mortgage Bonds				
1982	$ 52,770	$ 139,771	$	$ 192,541
1983	53,755	16,700		70,455
1984	47,050	16,700		63,750
1985	18,083	197,850		215,933
1986	25,590	8,750		34,340
1987-1996	221,276	87,500		308,776
1997-2006	200,901	1,612,094		1,812,995
2007-2020	2,870	775,000	855,000	1,632,870
Total Mortgage Bonds	$622,295	$2,854,365	$855,000	4,331,660
Current Portion Net of Reacquired Bonds ($34,017,000 held in treasury) Included in Current Liabilities				(202,071)
Unamortized Discount Net of Premium				(27,050)
Total Mortgage Bonds Included in Long-term Debt				4,102,539
Other Long-term Debt (net of current portion)				11,926
PG&E Long-term Debt Included in Long-term Debt				4,114,465
Pacific Gas and Electric Finance Company N.V.				
Guaranteed Debentures 16% due 1988				74,285
Pacific Gas Transmission Company				
Mortgage Bonds 5¼% Series, due January 1986				17,257
Mortgage Bonds 8% Series, due November 1990 (net of $1,949,000 held in treasury)				16,505
Subordinated Debentures 5½%, due February 1986				336
Bank Term Loan				145,000
Total Long-term Debt				179,098
Unamortized Discount, 8% Series				(43)
Current Portion Included in Current Liabilities				(24,209)
PGT Long-term Debt Included in Long-term Debt				154,846
Eureka Energy Company				
Notes Payable – 10.5% interest, due 1983-1996 (net of current portion)				3,572
Natural Gas Corporation of California				
Other Long-term Debt (net of current portion)				86
Total Long-term Debt of PG&E and Subsidiaries				$4,347,254

PG&E is required, according to provisions of the First and Refunding Mortgage, to make semi-annual sinking fund payments on February 1 and August 1 of each year for the retirement of the bonds of PG&E equal to ½ of one percent of the aggregate bonded indebtedness outstanding on the preceding November 30 and May 31, respectively. Bonds of any series may be used to satisfy this requirement.

PGT's First Mortgage Pipeline Bonds and subordinated debentures, which are solely the obligation of PGT, are subject to redemption, at specified redemption prices, through the operation of a sinking fund or in larger increments at PGT's option, depending upon the series and redemption date. The debentures are subordinated in right of payment to mortgage debt and certain other indebtedness.

On December 31, 1981, PGT converted short-term borrowings to a $145 million bank term loan to finance the Western Leg Prebuild of the Alaska Natural Gas Transportation System. The financing was obtained from a group of nine banks and is repayable in seven annual installments. The interest rate at December 31, 1981 is 18.13% and is subject to recalculation in accordance with the terms of the credit agreement in December, 1983.

For the years 1982 through 1986, the Company's combined aggregate amount of debt maturing and sinking fund requirements calculated as of December 31, 1981 in accordance with the mortgage bond indenture are $262,647,000, $138,123,000, $130,305,000, $281,505,000 and $95,493,000 respectively.

On January 4, 1982 PG&E issued $30,000,000 of its 81B First and Refunding Mortgage Bonds at 16.9%.

On January 5, 1982 Finance issued 15.75% Guaranteed Debentures in the amount of $80,000,000 maturing in 1989.

Note 4 Taxes on Income

Taxes on income generally reflect amounts currently payable with the exception of taxes related to changes in regulatory balancing accounts, investment tax credits, nuclear fuel financing, major construction projects, and subsidiaries' gas exploration costs. Changes in regulatory balancing accounts are not included in federal and state income tax returns until such changes are billed to customers. The net unbilled amount included in the balancing accounts at December 31, 1981 was approximately $303,000,000 which will result in an additional tax payment of $155,000,000 when billed. This amount is included in Accrued Taxes. In addition, the Company has available investment tax credits of approximately $78,000,000 to reduce federal income tax payments for years after 1981.

The reasons for the differences between the reported income tax expense and the amount computed by applying the federal income tax rate of 46% to income before taxes are:

	1981	1980	1979
	In Thousands		
Computed provision	$287,144	$274,674	$250,943
Increases (reductions) resulting from:			
Investment tax credits	(72,063)	(55,669)	(37,920)
State tax on income	13,692	14,225	13,165
Allowance for equity and borrowed funds used during construction	(131,085)	(116,703)	(89,607)
Tax depreciation in excess of book depreciation	(5,247)	(521)	(10,836)
Other overhead construction costs	(17,678)	(20,788)	(18,167)
Repair allowance	—	(11,500)	(11,270)
Property taxes	(6,177)	(5,486)	(2,874)
Property removal expenses	(6,900)	(5,520)	(5,060)
Other – net	(2,066)	(365)	(1,081)
Total	$ 59,620	$ 72,347	$ 87,293

Income tax expense (credit) is included in the consolidated financial statements as follows:

	1981	1980	1979
	In Thousands		
Included in operating expenses	$124,216	$123,698	$100,071
Included in other income	(64,596)	(51,351)	(12,778)
Total	$ 59,620	$ 72,347	$ 87,293

The components of income tax expense (credit) are:

	1981	1980*	1979*
	In Thousands		
Current			
Federal	$13,122	$72,138	$(76,000)
State	17,743	50,775	—
Canadian	667	1,454	121
Deferred			
Taxes related to changes in regulatory balancing accounts			
Federal	(9,128)	(122,366)	211,017
State	(2,107)	(28,249)	41,286
Taxes related to nuclear fuel financing			
Federal	13,608	—	—
State	3,142	—	—
Amortization of deferred taxes on defense facilities			
Federal	(2,694)	(2,694)	(2,694)
State	(251)	(251)	(251)
Taxes related to subsidiaries' gas exploration costs			
Federal	29,510	16,382	16,303
State	6,829	4,068	3,812
Canadian	263	(387)	570
Investment tax credits (Federal only)			
Major construction projects	18,114	17,078	14,293
Utilized against deferred taxes	(20,422)	69,477	(145,429)
Amortization of deferred ITC	(8,776)	(5,078)	24,265
Total	$59,620	$72,347	$ 87,293

*Changed to conform to 1981 format.

Note 5 Short-term Borrowings

The Company maintains lines of credit with various banks, principally to support the sale of commercial paper. At December 31, 1981 these lines of credit totaled $757,243,000. At no time during the year were the lines of credit used for direct bank borrowings. The Company also maintains a credit arrangement with five banks totaling $100,000,000 for the sale of bankers acceptances which are used to pay for Canadian natural gas. The usual maturity for commercial paper is 10 to 90 days and no more than 60 days for bankers acceptances.

A & S also maintains a line of credit for operations with four banks totaling $24,000,000 (Canadian) which was unused as of December 31, 1981.

The Company also has a provision with Pacific Energy Trust (Energy) to borrow an amount up to the difference between $300,000,000 and Energy's investment in nuclear fuel, purchased from PG&E in February 1981, with a maximum of $120,000,000. As of December 31, 1981, the Company had no outstanding borrowings with respect to this provision.

The Company compensates banks for lines of credit and other banking services by fee payments.

Short-term borrowings and interest rates thereon were as follows:

For the Years Ended December 31,	1981	1980
	In Thousands (except percentages)	
Balance of Short-term Borrowings Outstanding at End of Period		
Commercial Paper	$820,428	$591,955
Bankers Acceptances	$100,000	$110,000
Bank Loans	$ 8,236	$ 8,261
Weighted Average Interest Rates for Short-term Borrowings Outstanding at End of Period		
Commercial Paper	13.5%	17.9%
Bankers Acceptances	13.1%	16.1%
Bank Loans	18.7%	14.1%

Note 6 Commitments and Contingencies

Construction expenditures for the year 1982 are estimated to be $1,400,000,000.

The Company is a member of Nuclear Mutual Limited (NML) and Nuclear Electric Insurance Limited (NEIL), which were established by the utility industry to provide insurance coverage against property damage to members' nuclear generating facilities whether under construction or in operation. In the event of property damage to a nuclear plant of a member utility, the Company may be subject to a maximum assessment of approximately $27,000,000 if losses exceed premiums, reserves and other NML or NEIL resources.

The Company's public liability for claims resulting from any nuclear incident is limited to $560,000,000 under provisions of the Price-Anderson Act (Act). The coverage for this liability is provided by insurance, assessments and government indemnification under the Act. The Company is subject to a retrospective assessment of up to $5,000,000 for each of its licensed reactors over 100,000 kw in the event there is a nuclear incident involving any of the nation's licensed reactors. There is a limitation of $10,000,000 in retrospective assessments in any one year. As of December 31, 1981, the Company had one reactor subject to this assessment.

The CPUC as a matter of policy has in the past disallowed recovery of allowance for equity and borrowed funds used during construction on unsuccessful projects of other utilities in the state, although it has consistently allowed utilities under its jurisdiction to amortize the costs other than AFUDC of abandoned projects and has established rates to cover that amortization. There is no reasonable way to estimate which projects, if any, may be abandoned and therefore the aggregate amount of possible loss of AFUDC if the CPUC adheres to its past policy. The Company intends to pursue vigorously any avenue available to it to recover all legitimate costs of any project that must be abandoned.

The Company advised the Nuclear Regulatory Commission's Atomic Safety and Licensing Board that a final decision to restart the nuclear power plant unit at Humboldt Bay will be deferred until retrofit requirements are defined. The net investment in the power plant is approximately $61,000,000. If a decision is made not to restart the nuclear unit, substantially all costs are expected to be recovered through future regulatory proceedings.

The Company is required to make take-or-pay or minimum payments to Canadian gas producers if it does not take the contractual minimum annual volume of natural gas during a contract year. During 1981, the Company negotiated reductions in the minimum purchase requirements under Canadian gas purchase contracts through June 30, 1982, including a reduction in take-or-pay obligations under a substantial portion of the contracts with Canadian gas producers. The amended contracts with the producers also provide for reimbursement to the Company for payments made for gas not taken to the extent such prepaid gas is not delivered to the Company prior to the expiration of the contracts.

On February 4, 1981, the Company entered into an agreement with Energy to sell and leaseback nuclear fuel for use at the Diablo Canyon Nuclear Power Plant. On that date, the Company transferred to Energy its title and interest in the current nuclear fuel inventory for approximately $220,000,000; at December 31, 1980 approximately $217,000,000 was included in Construction Work in Progress. As of December 31, 1981, the Company had transferred nuclear fuel inventory valued at approximately $245,000,000. When the nuclear fuel is generating heat, the Company will make quarterly payments to Energy for the cost of fuel consumed which will include costs arising out of the ownership of the nuclear fuel.

The Company has entered into various arrangements to lease automotive equipment, computer equipment, office equipment and other incidental equipment and property which are accounted for as operating leases in accordance with CPUC ratemaking practices. The annual lease expenses are not material.

Note 7 Segment Information

For the Years Ended December 31,	Electric	Gas	Intersegment Eliminations	Total
	In Thousands			
1981				
Operating Revenues	$3,905,873	$2,288,702		$ 6,194,575
Intersegment Sales[1]	5,320	1,250,879	$(1,256,199)	—
Total Operating Revenues	3,911,193	3,539,581	(1,256,199)	6,194,575
Depreciation	220,422	83,057	—	303,479
Taxes on Income[2]	73,972	50,244	—	124,216
Other Operating Expenses[2]	3,160,104	3,215,766	(1,256,199)	5,119,671
Total Operating Expenses	3,454,498	3,349,067	(1,256,199)	5,547,366
Operating Income	$ 456,695	$ 190,514	$ —	$ 647,209
Construction Expenditures[3]	$ 917,805	$ 465,909		$ 1,383,714
Utility Assets[3]	$6,199,961	$2,795,776		$ 8,995,737
Construction Work in Progress[3]	3,283,466	87,456		3,370,922
Total Assets	$9,483,427	$2,883,232		$12,366,659
1980				
Operating Revenues	$2,927,841	$2,331,058		$ 5,258,899
Intersegment Sales[1]	4,549	812,833	$ (817,382)	—
Total Operating Revenues	2,932,390	3,143,891	(817,382)	5,258,899
Depreciation	204,878	75,832	—	280,710
Taxes on Income[2]	65,803	57,895	—	123,698
Other Operating Expenses[2]	2,256,563	2,842,163	(817,382)	4,281,344
Total Operating Expenses	2,527,244	2,975,890	(817,382)	4,685,752
Operating Income	$ 405,146	$ 168,001	$ —	$ 573,147
Construction Expenditures[3]	$ 973,785	$ 247,973		$ 1,221,758
Utility Assets[3]	$5,615,192	$2,601,526		$ 8,216,718
Construction Work in Progress[3]	2,985,187	93,298		3,078,485
Total Assets	$8,600,379	$2,694,824		$11,295,203
1979				
Operating Revenues	$2,463,845	$1,900,624		$ 4,364,469
Intersegment Sales[1]	3,440	556,354	$ (559,794)	—
Total Operating Revenues	2,467,285	2,456,978	(559,794)	4,364,469
Depreciation	183,995	66,869	—	250,864
Taxes on Income[2]	63,168	36,903	—	100,071
Other Operating Expenses[2]	1,834,935	2,222,490	(559,794)	3,497,631
Total Operating Expenses	2,082,098	2,326,262	(559,794)	3,848,566
Operating Income	$ 385,187	$ 130,716	$ —	$ 515,903
Construction Expenditures[3]	$ 943,911	$ 205,397		$ 1,149,308
Utility Assets[3]	$5,257,874	$2,487,076		$ 7,744,950
Construction Work in Progress[3]	2,521,809	44,004		2,565,813
Total Assets	$7,779,683	$2,531,080		$10,310,763

(1) Intersegment sales for 1981, 1980 and 1979 represent 35%, 26% and 23%, respectively, of Total Gas Revenues and less than 1% of Total Electric Revenues. Intersegment Electric and Gas Sales are accounted for at tariff rates prescribed by the CPUC.

(2) Taxes on Income and general corporate expenses are allocated to departments in accordance with the Uniform System of Accounts and requirements of the CPUC.

(3) Includes allocation of Common Utility Plant.

Note 8 Retirement Plan

The Company provides retirement plans covering substantially all employees. The cost of these plans charged to expense and utility plant for 1981, 1980 and 1979 was $66,000,000, $75,000,000 and $69,000,000, respectively. These amounts include amortization of past service cost. Costs of the retirement plans are accrued in accordance with an actuarial cost method (entry age normal method). The Company makes contributions to the plans equal to the amounts accrued for pension expense. The net effect of changes made in certain plan provisions and actuarial assumptions in 1981 resulted in the decreased pension expense. A comparison of accumulated plan benefits and plan net assets for the Company's defined benefit plans is presented here:

January 1,	1981	1980
	In Thousands	
Actuarial present value of accumulated plan benefits:		
Vested	$ 972,000	$693,000
Nonvested	51,000	53,000
Total present value of accumulated plan benefits	$1,023,000	$746,000
Net assets available for benefits	$1,023,000	$797,000

The assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7 percent in 1981 and 1980. The actuarial present values are based on historic pay as prescribed by the FASB.

Opinion of Independent Certified Public Accountants

To the Stockholders and the Board of Directors of Pacific Gas and Electric Company

We have examined the consolidated balance sheet of Pacific Gas and Electric Company (a California corporation) and its subsidiaries as of December 31, 1981, and the related consolidated statements of income, funds used for construction, and common stock equity and preferred stock for the year then ended. Our examination was made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances. The consolidated financial statements for Pacific Gas and Electric Company and subsidiaries for the years ended December 31, 1980 and 1979, were examined by other auditors whose report dated February 17, 1981 expressed an unqualified opinion on those statements.

In our opinion, the consolidated financial statements referred to above present fairly the financial position of Pacific Gas and Electric Company and its subsidiaries as of December 31, 1981 and the results of their operations and funds used for construction for the year then ended, in conformity with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

ARTHUR ANDERSEN & CO.

San Francisco, California
February 17, 1982

Supplementary Financial Information

(Unaudited)

Information Required by Statement of Financial Accounting Standards No. 33

For many years the purchasing power of the dollar, measured by consumer and wholesale price indices, has declined each year. This decline in purchasing power of the dollar is commonly called "inflation."

Many complex theories have been proposed in an attempt to eliminate the inflation component from reported net income, but no solution has emerged that commands general acceptance. In 1979 the Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 33 requiring that certain supplemental financial information be presented showing historical information converted to two bases—constant dollars and current costs—using specified techniques.

Constant dollar amounts so required and as reported herein represent historical amounts converted to dollars having approximately the same purchasing power as the real dollar had in mid-1981 as measured by the Consumer Price Index for All Urban Consumers.

Current cost amounts as required by SFAS No. 33 purport to represent the price in current dollars the Company would expect to pay for its assets if it could obtain them at today's prices. Because of siting, environmental and other problems involved in constructing property today that were not present when the Company's plant was originally constructed, there is no reasonable way for the Company to estimate the cost of replacing its assets. Therefore, for purposes of the current cost calculation, the Handy-Whitman Index of Public Utility Construction Costs for the Pacific Coast Division was applied to historical cost of surviving plant in developing the required current cost. This results in current cost calculations being computed from a construction index whereas constant dollar calculations are computed from an overall index.

Following SFAS No. 33 requirements, the only amounts adjusted in arriving at the net income amounts adjusted for changing prices were net utility plant and depreciation expenses. As prescribed in SFAS No. 33, income taxes were not adjusted.

The current year's provisions for depreciation on the constant dollar and current cost amounts of utility plant were determined by applying the Company's depreciation rates to the constant dollar and current costs.

The Company has serious reservations as to whether the required supplemental financial information is appropriate for measuring the impact of inflation on a utility regulated, as PG&E is, on a cost-of-service basis. This information is presented solely because it is required to be presented. It should be clearly understood that the required information is complicated, difficult to understand and because of the permitted subjectivity inherent in developing this prescribed information, unwarranted comparisons and inferences may result.

Consolidated Statement of Income from Continuing Operations Adjusted for Changing Prices As Required By SFAS No. 33

For the Year Ended December 31, 1981	Conventional Historical Cost	Constant Dollar	Current Cost
	In Thousands		
Operating Revenues	$6,195,000	C$6,195,000	C$6,195,000
Operation, Maintenance and Other	5,327,000	5,327,000	5,327,000
Depreciation	303,000	671,000	866,000
Total	5,630,000	5,998,000	6,193,000
Income from continuing operations (excluding adjustment to net recoverable cost)	$ 565,000	C$ 197,000*	C$ 2,000
Increase during the year in specific prices of utility plant**			C$ 905,000
Adjustment to net recoverable cost		C$ (380,000)	507,000
Effect of increase in general price level			(1,597,000)
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost			(185,000)
Reduction of purchasing power loss through debt financing		481,000	481,000
Net		C$ 101,000	C$ 296,000

C$—Dollars having approximately the same purchasing power as the real dollar had in mid-1981.

*Including the adjustment to net recoverable cost, the loss from continuing operations on a constant dollar basis would have been C$183,000,000.

**At December 31, 1981, current cost of utility plant, net of accumulated depreciation was C$20,630,000,000 while historical cost or net cost recoverable through depreciation was $9,793,000,000.

Five-Year Comparison of Selected Consolidated Financial Data Adjusted for Effects of Changing Prices As Required by SFAS No. 33

For the Years Ended December 31,	1981	1980	1979	1978	1977
	In Thousands (except per share amounts)				
Operating Revenues	C$6,195,000	C$5,785,000	C$5,456,000	C$4,997,000	C$5,444,000
Historical Cost Information Adjusted for General Inflation					
Income from continuing operations (excluding adjustment to net recoverable cost)	C$ 197,000	C$ 191,000	C$ 269,000		
Income per common share (after dividend requirements on preferred stock and excluding adjustment to net recoverable cost)	C$ .50	C$ .62	C$ 1.49		
Net assets at year-end at net recoverable cost	C$3,807,000	C$3,913,000	C$4,033,000		
Current Cost Information					
Income (loss) from continuing operations (excluding adjustment to net recoverable cost)	C$ 2,000	C$ (55,000)	C$ 13,000		
Loss per common share (after dividend requirements on preferred stock and excluding adjustment to net recoverable cost)	C$ (1.04)	C$ (1.52)	C$ (.99)		
Excess of increase in general price level over increase in specific prices after adjustment to net recoverable cost	C$ (185,000)	C$ (486,000)	C$ (718,000)		
Net assets at year-end at net recoverable cost	C$3,807,000	C$3,913,000	C$4,033,000		
General Information					
Reduction of purchasing power loss through debt financing	C$ 481,000	C$ 722,000	C$ 793,000		
Cash dividends declared per common share	C$ 2.72	C$ 2.86	C$ 2.98	C$ 3.02	C$ 3.00
Market price per common share at year-end	C$ 20.37	C$ 21.53	C$ 27.37	C$ 29.82	C$ 35.04

C$ — Dollars having approximately the same purchasing power as the real dollar had in mid-1981.

Average consumer price index Base year 1967-100	272.7	247.0	217.4	195.4	181.5

Supplementary Financial Information (Continued)

(Unaudited)

Consolidated Quarterly Financial Data

Quarterly financial data for the four quarters of 1981 and 1980 are shown in the table below. Due to the seasonal nature of the utility business, operating revenues, operating income, and net income are not generated evenly by quarter during the year. The Company's common stock is traded on the New York and Pacific Stock Exchanges. The approximate number of common stockholders of record as of December 31, 1981 was 255,000. Dividends are paid on a quarterly basis and there are no material restrictions on present or future ability to pay dividends.

	4th	3rd	2nd	1st
	In Thousands (except per share amounts)			
1981				
Operating Revenues	$1,619,576	$1,620,272	$1,452,801	$1,501,926
Operating Income	$ 171,173	$ 179,417	$ 150,735	$ 145,884
Net Income	$ 135,534	$ 158,344	$ 138,723	$ 132,005
Earnings Per Common Share	$ .78	$ .97	$ .83	$ .82
Dividends Declared Per Common Share	$ .68	$ .68	$ .68	$ .68
Common Stock Price Per Share				
High	$ 23⅛	$ 24⅛	$ 23⅜	$ 22⅛
Low	$ 20	$ 20⅝	$ 19½	$ 20
1980				
Operating Revenues	$1,485,740	$1,280,296	$1,163,692	$1,329,171
Operating Income	$ 133,125	$ 140,193	$ 146,103	$ 153,726
Net Income	$ 123,377	$ 145,133	$ 124,705	$ 131,555
Earnings Per Common Share	$ .80	$ 1.00	$ .86	$ .93
Dividends Declared Per Common Share	$ .65	$ .65	$ .65	$ .65
Common Stock Price Per Share				
High	$ 22⅛	$ 24¾	$ 24¾	$ 23¼
Low	$ 19⅝	$ 21⅜	$ 20¼	$ 19¼

Consolidated Comparative Statistics

For the Years Ended December 31,	1981	1980	1979	1978	1977
Electric Statistics					
Sales (Thousands of KWH)					
Residential	**19,575,283**	19,329,190	19,605,541	18,314,721	17,383,011
Commercial	**23,014,972**	22,254,740	22,062,291	20,773,342	22,376,516
Industrial	**16,401,293**	14,801,260	15,253,371	14,815,289	14,354,359
Other Electric Utilities	**2,676,998**	1,906,465	2,807,249	2,232,563	3,957,141
Total Sales to Customers	**61,668,546**	58,291,655	59,728,452	56,135,915	58,071,027
Revenues (In Thousands)					
Residential	**$1,128,851**	$ 998,130	$ 693,368	$ 720,112	$ 661,502
Commercial	**1,516,283**	1,318,193	925,577	1,036,430	1,035,551
Industrial	**860,577**	699,073	461,653	531,593	498,462
Other Electric Utilities	**117,791**	71,926	67,740	69,855	103,890
Miscellaneous & Other	**77,407**	63,904	54,226	47,398	45,739
Regulatory Balancing Account Changes	**204,964**	(223,385)	261,281	(308,455)	9,989
Total	**$3,905,873**	$2,927,841	$2,463,845	$2,096,933	$2,355,133
Net System Output (Millions of KWH)	**72,829**	69,962	70,339	67,669	65,428
Net System Output — Percent					
Hydroelectric Plants	**14.6%**	19.0%	16.8%	19.9%	9.2%
Thermal Electric Plants	**54.0%**	50.5%	59.1%	49.5%	72.4%
Other Producers	**31.4%**	30.5%	24.1%	30.6%	18.4%
Net System Peak Demand — KW	**13,680,100**	13,440,400	13,215,200	12,970,600	12,191,800
Total System Capacity — KW (at annual peak)	**16,845,500**	15,079,600	15,084,900	13,436,000	13,947,800
Gas Statistics					
Sales (Thousands of MCF)					
Residential	**195,631**	216,184	234,295	220,076	223,732
Commercial	**128,758**	146,827	143,707	144,161	163,828
Industrial	**171,769**	161,060	186,165	138,976	162,529
Other Gas Utilities	**35,135**	34,821	36,013	9,926	7,810
Total Sales to Customers	**531,293**	558,892	600,180	513,139	557,899
Company Use (electric generation)	**280,990**	202,964	216,062	125,636	217,272
By Subsidiary Companies (in U.S.)	**341**	151	134	119	12
Total	**812,624**	762,007	816,376	638,894	775,183
Revenues (In Thousands)					
Residential	**$ 764,468**	$ 799,307	$ 555,017	$ 432,865	$ 414,087
Commercial	**607,417**	626,611	406,497	346,229	365,623
Industrial	**794,786**	708,259	499,242	340,546	366,293
Other Gas Utilities	**158,433**	148,074	85,867	18,384	14,349
Miscellaneous	**2,290**	(6,560)	7,128	4,315	4,773
Regulatory Balancing Account Changes	**(276,749)**	(133,807)	176,354	193,960	(19,477)
Subsidiary Companies (U.S. and Canada)	**238,057**	189,174	170,519	136,141	128,749
Total	**$2,288,702**	$2,331,058	$1,900,624	$1,472,440	$1,274,397
Gas Purchased for U.S. Operations (Thousands of MCF)	**835,684**	781,643	843,381	711,052	817,745
Average Cost Per MCF	**$3.29**	$3.10	$2.16	$1.81	$1.53

Directors & Officers

Directors

John F. Bonner[1]
Executive Consultant and Former President and Chief Executive Officer, Pacific Gas and Electric Company

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

Richard P. Cooley[2,5]
Chairman of the Board and Chief Executive Officer, Wells Fargo Bank, N.A.

Charles de Bretteville[2,4,5]
Former Chairman of the Board, The Bank of California, N.A.

Myron Du Bain**
Chairman of the Board, President and Chief Executive Officer, Fireman's Fund Insurance Companies

Alfred W. Eames, Jr.[1,3]
Former Chairman of the Board, Del Monte Corporation (food products and related services)

Lewis S. Eaton[3]
Chairman of the Board and President, Guarantee Savings and Loan Association

Robert B. Hoover[4]
Chairman of the Board, The Pacific Lumber Company

L. W. Lane, Jr.[5]
Chairman of the Board, Lane Publishing Company (publisher of Sunset Magazine)

Leslie L. Luttgens[4]
San Francisco Bay Area Community Leader

Richard B. Madden[1,3]
Chairman of the Board and Chief Executive Officer, Potlatch Corporation (diversified forest products)

Peter A. Magowan[3]
Chairman of the Board and Chief Executive Officer, Safeway Stores, Inc.

Frederick W. Mielke, Jr.[1,2,5]
Chairman of the Board and Chief Executive Officer, Pacific Gas and Electric Company

Mervin G. Morris[2,4]
President, Morris Management Company (investments)

Richard H. Peterson[5]
Consultant and Former Chairman of the Board, Pacific Gas and Electric Company

John B. M. Place[2,4]
Chairman of the Board and Chief Executive Officer, Crocker National Bank

Wilson C. Riles[3]
State of California Superintendent of Public Instruction

Barton W. Shackelford[1,2]
President and Chief Operating Officer, Pacific Gas and Electric Company

Emmett G. Solomon***
Former Chairman of the Board, Crocker National Bank

John Lyons Sullivan[1,5]
Rancher

Officers

Frederick W. Mielke, Jr.[M]
Chairman of the Board and Chief Executive Officer

Barton W. Shackelford[M]
President and Chief Operating Officer

Stanley T. Skinner[M]
Executive Vice President

John A. Sproul[M]
Executive Vice President

John S. Cooper[M]
Senior Vice President Personnel

Malcolm H. Furbush[M]
Senior Vice President and General Counsel

Ellis B. Langley, Jr.[M]
Senior Vice President Operations

Malcolm A. MacKillop[M]
Senior Vice President Corporate Relations

George A. Maneatis[M]
Senior Vice President Facilities Development

G. Stanley Bates
Vice President General Construction

Donald A. Brand
Vice President Engineering

Howard P. Braun
Vice President Electric Operations

Robert W. Brooks
Vice President Gas Planning and Acquisition

Richard A. Clarke
Vice President and Assistant to the Chairman

George F. Clifton, Jr.
Vice President Customer Operations

Nolan H. Daines
Vice President Planning and Research

Joseph Y. DeYoung
Vice President Division Operations

James T. Doudiet
Vice President Finance and Treasurer

William M. Gallavan
Vice President Rates and Valuation

Grant N. Horne
Vice President Public Relations

Elmer F. Kaprielian
Vice President Fuels Planning and Acquisition

John E. Koehn
Vice President Governmental Relations

Gary E. Lavering
Vice President and Comptroller

Howard M. McKinley
Vice President Gas Operations

Richard K. Miller
Vice President General Services

Robert Ohlbach
Vice President and General Attorney

James O. Schuyler
Vice President Nuclear Power Generation

John F. Taylor
Vice President and Corporate Secretary

William H. Wallace
Vice President Computer Systems and Services

Mason Willrich
Vice President Corporate Planning

David B. Allison
Assistant Secretary

Brian L. McGrath
Assistant Secretary

Anthony J. Duffy
Assistant Treasurer

Gordon R. Smith
Assistant Treasurer

1 Member Executive Committee
2 Member Finance Committee
Frederick W. Mielke, Jr., Chairman
3 Member Audit Committee
Richard B. Madden, Chairman
4 Member Compensation and Management Development Committee
Robert B. Hoover, Chairman
5 Member Advisory Nominating Committee
Frederick W. Mielke, Jr., Chairman
*Advisory Director
**Resigned from the Board in September 1981
***Retired from the Board in February 1981
M Member Management Committee

PG&E Service Area

Division Managers

1 **Humboldt Division**
D.C. Albright
Eureka

2 **Shasta Division**
R.J. LaRue, Jr.
Red Bluff

3 **De Sabla Division**
J.C. Keyser
Chico

4 **North Bay Division**
R.A. Draeger
San Rafael

5 **Colgate Division**
J.L. Kirkegaard
Marysville

6 **Drum Division**
R.E. Metzker
Auburn

7 **Sacramento Division**
S.E. Howatt
Sacramento

8 **San Francisco Division**
J.A. Fairchild
San Francisco

9 **East Bay Division**
F.C. Marks
Oakland

10 **Stockton Division**
C.R. Martin
Stockton

11 **San Jose Division**
V.H. Lind
San Jose

12 **Coast Valleys Division**
R.D. Mullikin
Salinas

13 **San Joaquin Division**
G.N. Radford
Fresno

Stockholders' Calendar
Schedule of Dividend
Payment Dates—1982

Common Stock
January 15
April 15
July 15
October 15

Preferred Stock
February 16
May 15
August 16
November 15

Stock Exchange Listings
Common stock of the Company is listed on the New York and Pacific Stock Exchanges. Preferred stocks of the Company are listed on the American and Pacific Stock Exchanges.

Annual Meeting
Proxies will be solicited by the Board of Directors for the annual meeting to be held at the Masonic Auditorium 1111 California Street, San Francisco, California, on Wednesday, April 21, 1982, at 2:00 p.m. In connection with such solicitation, it is expected that the proxy statement and form of proxy will be mailed to stockholders on or about March 12, 1982.

Stock Transfer Agent
L.H. Gunter
Office of the Company
San Francisco

Registrar of Stock
Wells Fargo Bank, N.A.,
San Francisco

Executive Office
Pacific Gas and Electric Company
77 Beale Street, San Francisco
California 94106

Annual Report for 1981 on Form 10-K
A copy of the Company's report for 1981 filed with the Securities and Exchange Commission on Form 10-K will be provided to stockholders upon written request to the Vice President and Corporate Secretary at the above address.

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94106

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Pacific Gas and
Electric Company