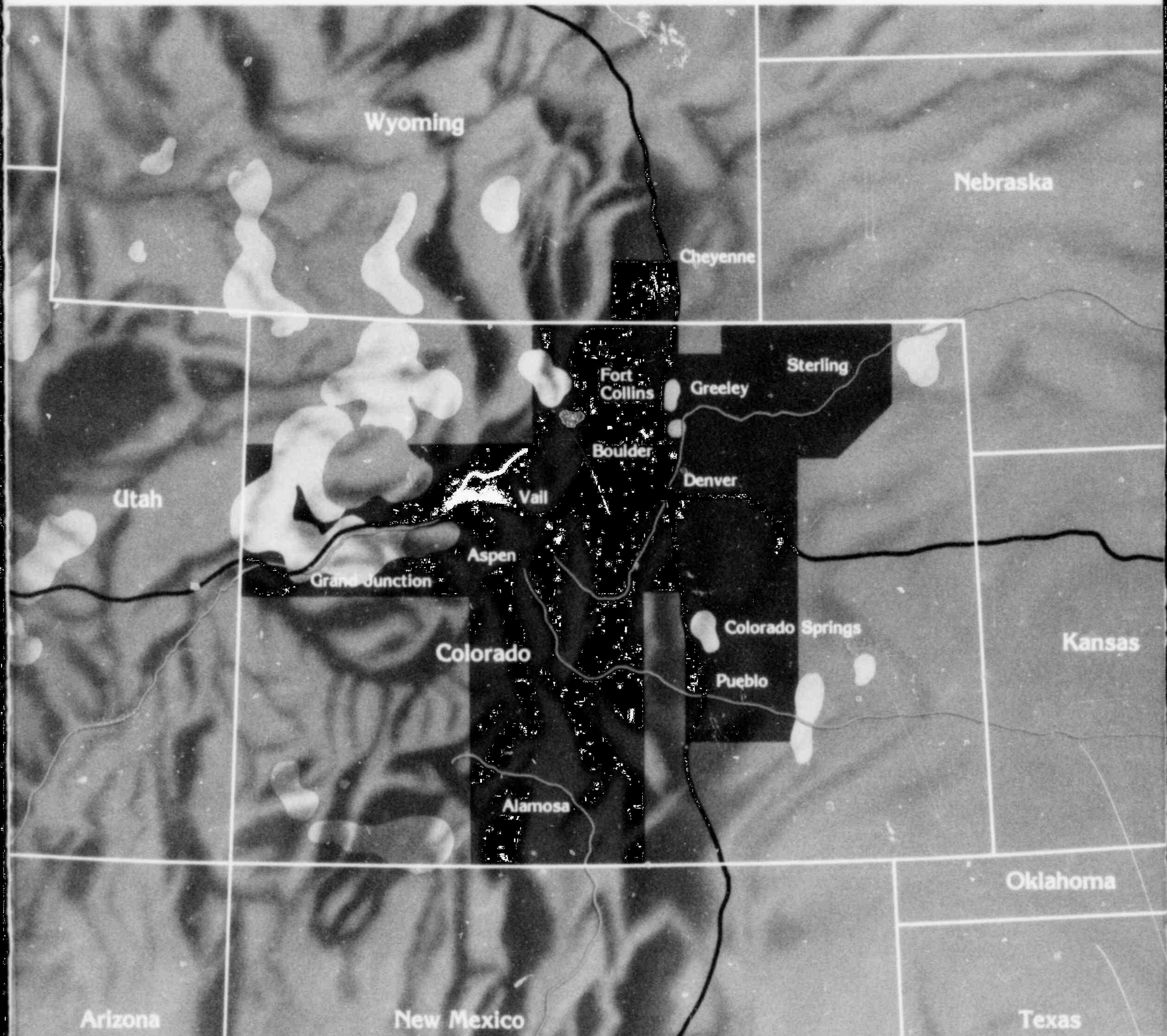
Public Service
Company of Colorado

1981 Annual Report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Kansas
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Oklahoma
Arizona
New Mexico
Texas

Annual Meeting

Annual Meeting Scheduled May 4
The 1982 Annual Meeting of Shareholders will be held Tuesday, May 4. This year's meeting is at Boettcher Concert Hall in the Denver Center for the Performing Arts, located at 950 13th Street, just a few blocks from the Company's headquarters in downtown Denver. The meeting will begin at 2:00 p.m. (MDT). Notice of the Annual Meeting, proxy statements and forms are mailed approximately 30 days before the meeting date. Management looks forward to welcoming all shareholders who will be able to attend.

For Additional Information . . .
A copy of Public Service Company's 1981 Annual Report to the Securities and Exchange Commission on Form 10-K and the 1971-1981 Financial and Statistical Review may be obtained without charge by returning the request card located on the inside back cover of this Annual Report, or by writing to Shareholder Services, P.O. Box 840, Denver, Colorado 80201.

It's a Century Later and We're Serving Another Colorado Frontier

Public Service Company of Colorado was in business more than 100 years ago when people came in search of gold and silver. We helped them build cities and railroads, businesses and farmlands.

Now, Coloradans are looking for oil, natural gas, shale, coal and other energy sources. Once again, we're helping . . . by providing the electricity and natural gas for these emerging technologies and the society they breed, and by constantly planning for the energy needs of those inevitable tomorrows.

Of course, we're much more sophisticated now . . . and a lot bigger. We've built a network of technologically-advanced electric generating facilities. And, for the most part, we run our plants with coal — the least expensive, most abundant fuel available to us. That helps keep our costs to our customers as low as possible in an age of rampant inflation. And we have a high-temperature, gas-cooled nuclear plant that is one of the most thermal efficient units you'll find in the power industry.

We're in the natural gas business as the major distributor to customers throughout the state, heating their homes and fueling a gamut of industrial processes.

Not only do we supply energy, but we search for it . . . broadening our programs to find and deliver to an energy-oriented society the oil and gas that lies waiting beneath the vast Rocky Mountain region.

To stay in step with the state's expanding economy, we should keep building electric generating facilities. And we're going to keep seeking opportunities for corporate growth. In this way, we will be around when Colorado's next frontier comes along.

Service Territory Map

Public Service Company Service Territory

Areas where Fuelco has leased acreage

Oil shale development

Table of Contents

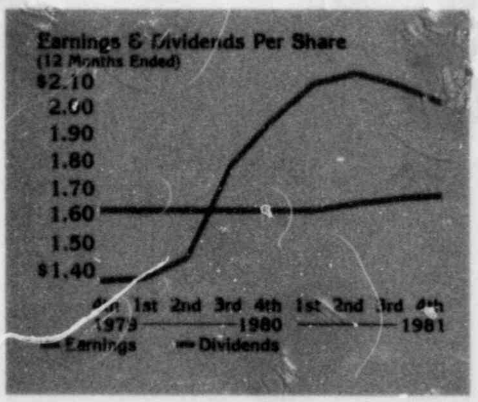
Public Service Company of Colorado is an investor-owned electric, natural gas and steam utility. The Company has six subsidiaries: Cheyenne Light, Fuel and Power Company; Home Light and Power Company; Fuel Resources Development Co. (Fuelco); Western Slope Gas Company; Bannock Center Corp.; and 1480 Welton, Inc.

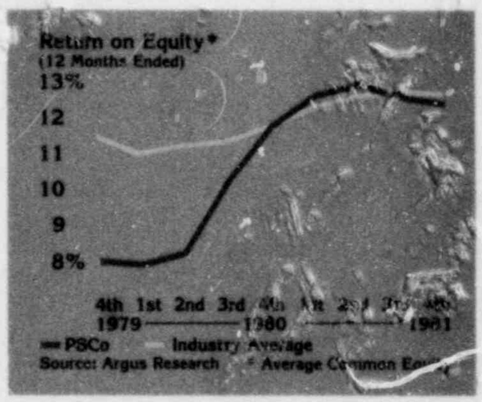
Note To Shareholders:
The 1981 Annual Report is layered to provide you with as much information about the Company as you need. The Year In Retrospect is designed to give you a brief report on the major events of 1981. The Management Commentary presents a broad overview of objectives, strategies and accomplishments. Subsequent sections categorize and expand the information presented in these two sections.

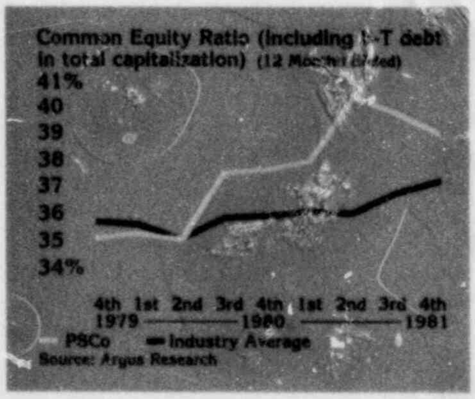
Design Unit 1

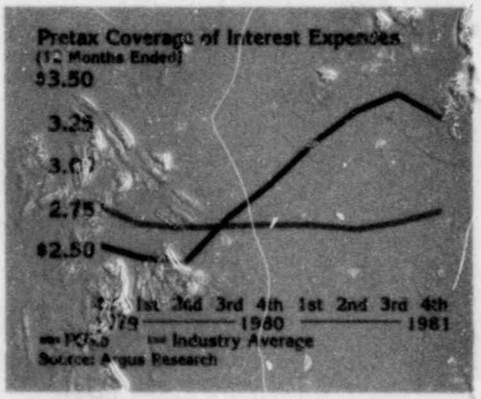
Financial Highlights

Financial	1981	1980	% Change
Earnings Per Share	$1.97	$1.92	2.6
Dividends Paid Per Share	$1.66	$1.60	3.8
Return on Average Equity	12.1%	11.6%	4.3
Common Equity Ratio (Year-End)	38.9%	37.5%	2.6
Operating Revenues (000)	$1,336,171	$1,155,644	15.6
Operating Expenses (000)	$1,195,115	$1,033,316	15.7
Net Income (000)	$ 100,755	$ 85,027	18.5
Capital Expenditures (000)	$ 256,747	$ 262,604	(2.2)
Plant Investment (000)	$2,754,493	$2,516,433	9.5
Operations			
Electric Revenues (000)	$ 742,104	$ 640,749	15.8
Kilowatt-Hour Sales (Millions)	15,473	15,194	1.8
Electric Customers	846,130	820,512	3.1
Gas Revenues (000)	$ 582,434	$ [illegible]	15.8
Mcf Sales (000)	176,120	[illegible]	(13.4)
Gas Customers	701,332	[illegible]	3.0









1981 In Retrospect

A Year Marked by Recovery And Unusual Weather

The measures of our financial health continued to improve steadily throughout 1981. Year-end earnings of $1.97 per share increased 3%, not as dramatic as the year before and somewhat short of earlier Company expectations. Energy sales growth rates plummeted in the face of the second warmest year in 110 years of Denver's recorded weather history. We estimate that these low energy sales adversely affected earnings by at least 15 cents and possibly closer to 20 cents per share. But these abridged earnings should not overshadow the overall improvements made in the Company's financial condition.

The impetus for our continued recovery from the financial difficulties of 1979 comes from several actions: regulatory approval within the past two years of higher prices for utility services; lower corporate borrowings during a time of historically-high interest rates; stringent in-house cost control programs; and cutbacks in Company construction expenditures.

(See Operations Review, Page 14)

Dividend Increase Consistent With Financial Growth

The annual dividend rate on outstanding common stock was raised to $1.68 per share. This 5% increase is in keeping with management's policy, subject to the Company's long-range financial objectives to maintain meaningful growth and regular increases in dividends.

(See A Look Ahead, Page 6)

Rate Increase Brightens Outlook for '82

The Company received a rate increase of $120 million in December. The request was for $189 million. The 9% revenue increase is significant because it will help propel the Company toward reaching some of its financial objectives for 1982. With limited planned expenditures for the construction of new major generating facilities, the higher revenues should enable us to earn closer to the 15.7% allowed return on shareholders' investment.

(See Financial Profile, Page 12)

New Power Plant Gives System A Much Needed Boost

The Pawnee electric generating plant was brought on line for commercial operation in December. The 500 megawatt coal-fired unit boosts the Company's generating capacity by approximately 20%. With firm purchased power agreements now under contract, we expect to meet projected peak demand periods through at least the next 5 years.

(See Operations Review, Page 14)

Major Plant Construction Still On Hold

With the completion of Pawnee, no new generating plant is under construction and none can be started before late 1983. Management will continue to defer construction of all major new generating facilities until it appears that capital can be raised at reasonable cost and without confiscating shareholder assets through the sale of common stock below book value. Shareholders endorsed this position in the form of a resolution passed at the 1981 Annual Meeting.

(See Management Commentary, Page 4)

The new Pawnee plant will help the Company stem the tide of rising energy demands.

New Financings In 1981 Down From Previous Year
Financings of capital expenditures during 1981 included the sale to the public of $53 million of common stock and $50 million of First Mortgage Bonds. This is a substantial reduction from the more than $200 million raised during 1980.
(See Financial Profile, Page 12)

Nuclear Plant Tests At Capacity Level
The Fort St. Vrain Nuclear Generating Station was tested briefly at its full 330 megawatt capacity level. Test data is now being evaluated as a preliminary step before authorization can be received to operate the plant at capacity.
(See Operations Review, Page 14)

Diversification: A Road Toward Financial Stability
Important steps were taken in 1981 to expand into businesses that offer earnings opportunities outside of regulated utility services. Management is putting the Company's oil and gas exploration subsidiary squarely into a profitable mode with exploration activity being stepped up for both gas and oil. A new subsidiary, Bannock Center Corp., was formed to engage in a variety of non-utility real estate activities in the growing Denver metropolitan area.
(See A Look Ahead, Page 6)

Cash Generated Internally Shows Marked Improvement
The combination of reduced construction expenditures and improved operating results brought internal cash generation to one of its highest levels in more than 10 years. Internal cash generation was 47% of 1981's net construction spending, up from 37% in 1980 and 19% in 1979.
(See A Look Ahead, Page 6)

Management Commentary

Of all the complex issues inherent in Colorado's growth, energy supply is perhaps the most basic and difficult. The delicate balance of factors that influence supply are not as well understood as they need to be. Nevertheless, the consequence of inadequate energy is a harsh reality.

We serve electricity and natural gas to Colorado's most populated areas. Our utility system is at the core of the state's industrial strength and social fabric. The emergence of Colorado as an oil shale center and a steady influx of newcomers in search of a more abundant life give rise to growth projections that are nothing short of dramatic.

One difficulty in preparing for the future is that our view of the future keeps changing. Even more difficult is the complex nature of the utility itself. Solutions to the energy supply dilemma are couched in the three most fundamental aspects of our business: *service, facilities* and *capital*.

Service

Service is the basic measure in this utility triangle. We are confident that we will be able to serve, adequately and reliably, the electric demands of our service territory through at least 1985. We brought the Pawnee plant on line in December, increasing our generating capability by approximately 20%. Significant progress was made in attempting to obtain approval to operate our nuclear plant at its full capacity. We also have arranged for the purchase of power from other utilities, which combined with Company generation, will assure us of a supply that is somewhat in excess of our peak demand projections.

For the longer term, purchased power is not a practical answer to our supply situation. Its availability in the late 1980s is likely to diminish; its price will be higher. Our system does not have enough electric generating capability to meet the energy demands expected in the late 1980s and 1990s. This brings us to the second point in the utility triangle.

New Facilities

The decisions that now have to be made regarding the construction of new facilities are pivotal. They hold the key to the quality of service we will be capable of providing by the end of this decade. The margin of electric supply is the determining factor in protecting the public from disruptive shortages.

Management is convinced that new generating facilities will be needed. We expect overall growth in electric demand to be higher than population growth because of the construction of large office and residential buildings, and the development of the oil shale industry and other energy-intensive industries. There is room, however, in determining the magnitude of our construction program. Changing trends in growth rates, consumer conservation and uncertainties in the development of oil shale make precise forecasting impossible.

If we are going to meet energy needs anticipated by the end of the 1980s, whatever their dimensions, we must reckon with the lengthy process of seeking permits for building new power plants now. Actual construction time for a generating unit is 4-5 years after necessary approvals are received, putting the earliest inauguration date for such a unit somewhere in 1987 or 1988.

Capital

The bottom line in any construction program is capital, the dollars invested in our business . . . the third part of the utility triangle. The ability to attract investment dollars on reasonable terms in today's capital markets may be the single most important element of our business. This is best illustrated by our experience with the building of Pawnee.

The original cost of the plant doubled because of rampant inflation and the record-high interest rates we had to pay for borrowing money. We were forced to sell sizable amounts of common stock at prices well below book value. These circumstances brought us to the brink of a credit crisis in 1979 and early 1980. A reduction in our construction expenditures in 1980 and 1981 helped in large measure to put us on the road to financial recovery.

Management and shareholders jointly resolved at our last Annual Meeting to prevent such a crisis from happening again. We will not commit ourselves to building new generating facilities until capital flows into our business on reasonable terms and we receive appropriate regulatory assurances that will help us see new construction to completion.

Among these assurances are regulatory principles that will enable us to recover the cost of financing in a new plant as soon as construction begins. But we must be quick to point out that regulation alone does not and cannot guarantee financial integrity. We are also subject to the forces of the markets in which we compete for capital. Regulation's role is to provide a realistic opportunity for us to achieve good financial results in that marketplace.

Responsibility
It is necessary for us to shift part of the responsibility for building new power plants from our shoulders to those who will create the need for them. We are breaking with traditional regulatory policies by asking that today's customers share more fully in the financial burden of building new facilities. We received approval in December to charge new customers for a greater part of the cost of bringing them onto our electric distribution system; and we're seeking a similar policy for natural gas customers.

We will insist that large industrial companies, such as those in oil shale development, pay the full incremental cost of the service they will demand from our system. Their future energy needs are currently clouded by the speculative nature of future oil prices and the extent of oil shale development in Colorado. We continue to hold discussions with representatives of the industry to reach mutual agreement on the means of pricing their utility requirements.

Natural Gas
The outlook for natural gas supply is more optimistic than that for electricity. The Natural Gas Policy Act of 1978 has succeeded in providing the economic incentives to explore and drill for new gas reserves. It has lifted the ceiling on gas prices, bringing them more in line with the prices of other energy sources. And it has assured us of adequate supplies to meet peak demand periods in the immediate future.

The rapid increase in prices has had a strong impact on our customers. While we support natural gas price deregulation, we oppose immediate deregulation of all natural gas. However, we would support a more realistic phased approach to complete deregulation.

Diversification
Management has decided to broaden its activities in non-regulated businesses that offer profit opportunities; in other words, diversify. We will continue our existing oil and gas exploration programs throughout the Rocky Mountain area. However, while maintaining approximately the same budget levels, we are entering into more joint ventures, farm-outs and other appropriate financial agreements in order to participate in the drilling of a greater number of gas and oil prospects. Until now, we have financed substantially all of our drilling programs with funds that have been either generated internally or borrowed. We also have established a subsidiary to explore a variety of non-utility real estate ventures in the growing Denver metropolitan area.

Success in these ventures would enhance our financial position and our ability to compete for the capital needed to build new electric generating facilities. A heralding of that success is premature. But it gives us cause for optimism as we formulate a business strategy consistent with our obligations to serve both our customers and our shareholders.

We take this opportunity to offer our sincerest thanks to all employees for their contributions and cooperation in helping reshape our Company to fit into the changing molds of our times.

For the Board of Directors,

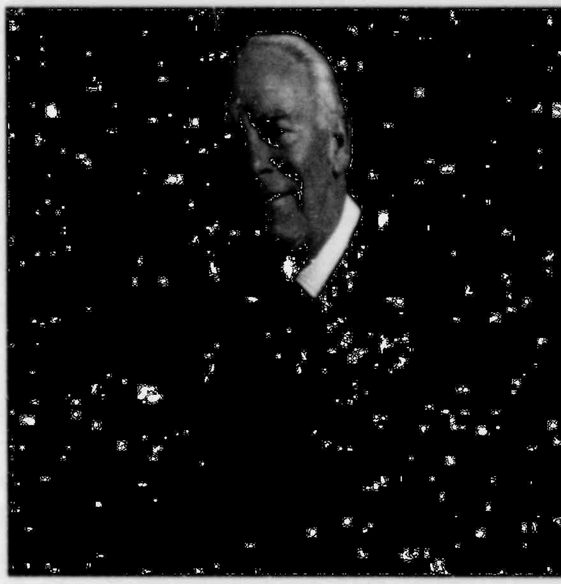
R. T. Person

R. T. Person
Chairman of the Board

R. F. Walker

R. F. Walker
President and Chief Executive Officer

February 5, 1982
Denver, Colorado



Top: R. T. Person

Bottom: R. F. Walker

A Look Ahead

They come to Colorado in droves. Some statistics tell us that 100 people move into the state every day. We know that our annual gas and electric customer growth rate over the past 10 years has floated between 4 and 5%. In the next 10 years, annual growth is projected to be in the 3-4% range.

The 1980 census recorded the state's population at 2.9 million. By the year 2000, the population should be approaching 4.5 million. We estimate that almost 80% of the state's population lives in our service territory. By far the largest concentration is in the Denver metropolitan area.

Denver is a city in transition. It has emerged as the commercial, financial, cultural and transportation hub of the Rocky Mountain West. New office skyscrapers on almost every other downtown corner attest to its new-found prominence. The influx of a gamut of service businesses is part of the supporting cast of energy exploration and production industries that are making Colorado the newest energy frontier.

Oil Shale Growth

The development of oil shale and other energy sources on Colorado's Western Slope is turning "one-gas-station" towns into fledgling metropolitan centers. One scenario calls for oil shale production of 250,000 barrels a day by 1990; 900,000 barrels daily by the year 2000. The complexity of the issues surrounding the development of energy sources makes precise forecasting difficult. Federal subsidies will stimulate at least moderate production levels. By 1990, we expect to be providing 300 megawatts of electricity to oil shale facilities in our service territory.

The demands this growth will place on Colorado's economy cannot be sidestepped. And that includes the need for utility services. During the next decade, we expect electric sales to increase at about a 4% annual rate, being somewhat tempered from past growth rates by the rising costs for utility services and conservation. Gas sales are likely to grow at about 2% annually.

We must have sufficient generating capability or purchased power to meet the maximum demand our customers can place on our system at any given time. During the next five years, this rate of increase is projected at 4% annually.

New Plant Needed

This projected growth indicates a need for additional generating facilities beyond 1985. We have Company-owned capacity and sufficient purchased power under contract to meet projected peak demand periods through that time. New capacity must be obtained for the demands of the late 1980s. Purchased power availability is almost certainly expected to taper off as other utilities meet the increased demands on their systems.

Our load forecast indicates the need for two additional 500 megawatt coal-fired units to be completed in the next 10 years. A potential site for these units is located along the Arkansas River in Southeastern Colorado. The projected cost of the units is $1.5 billion. Site acquisition work and preliminary engineering have been started so that we will be able to complete the first unit expeditiously if and when circumstances permit. It would take approximately 15 months just to get the necessary approvals. Add at least another four and a half years to construct the first unit. A second unit would require two more years.

We expect to set the approval process in motion in 1982. But until a commitment is made to build a facility we will remain flexible with respect to the scope of our construction program, the changing demands of the service territory, selection of other plant sites and alternative strategies in solving the energy supply dilemma.

Spending Scenarios

Since the timing of expenditures on additional generating units is uncertain at this point, we have created a range of scenarios for construction expenditures during the next several years. If we do *not* construct new generating units, we foresee expenditures averaging about $240 million a year, for a total of $1.2 billion through 1986. That entire amount is for repair and upgrading of existing plant, additional transmission and distribution facilities, and subsidiary spending.

If we decide to construct new units, beginning no sooner than late 1983, we will require approximately an additional $960 million during the next five years.

This would bring construction expenditures to $2.1 billion for the five years ended 1986. Whichever scenario is chosen, we intend to manage our expansion programs with a clear view of all the risks involved. The scenario we choose will be the one that will continue our financial recovery and accomplish our ambitious long-term objectives.

Regulatory Issues

Future directions for our Company will be guided, in part, by what transpires in the regulatory arena. There are two significant issues that we'll focus on in the near future: a full future test year and a cash return on construction work in progress (CWIP). The use of 1981 forecasted data in determining rates in the December rate case decision was a progressive stride in combating the traditional problem of regulatory lag.

Magnificent concert hall lights up Denver's emergence as a cultural center.

We will continue to urge the Colorado Public Utilities Commission (CPUC) to adopt a full future test year in any future rate cases. If, for example, we file for an increase during 1982, that request will be based on Company operating and financial data projected for calendar year 1983. If the CPUC were to accept a 1983 test year and issued its decision in 1982, rates would be brought more in line with our operating costs. This, in turn, would help us to realize a return to shareholders that is closer to what is allowed by the CPUC.

The CPUC has neither accepted nor rejected the idea of a full future test year; it has suggested that if we employ the full future test year concept we should also present data based on the current test year, as we did in the most recent filing.

If and when the Company requests approval for a major new generating unit, it will ask the CPUC to allow the Company to begin earning a cash return on the cumulative portion of investment in the plant. The CPUC did allow us to put 40% of the then-completed expenditures on the Pawnee plant in our rate base as of June 1980. But we were unable to be fully compensated for the remainder — and major portion — of our large investment until the plant went into operation in December. The implementation of a cash return on CWIP at the outset of a construction program would ease the heavy burden of raising capital in a very selective investment market.

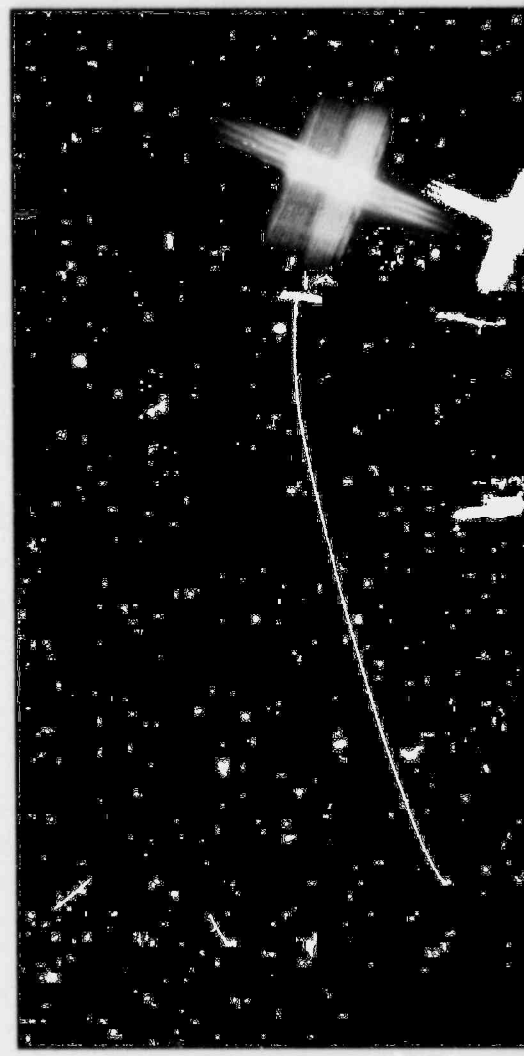
Financial Objectives

Setting financial goals and objectives for a utility in today's capital markets is a challenging exercise in flexibility.

We have set targets that will provide us with the necessary results consistent with a large construction program. Based on recent economic and inflationary experience, the loss of two rating levels is possible during construction. In order to avoid such a downgrading, we think our bonds should be rated double A before we try to double plant investment over a seven-year construction period. This means capitalization ratios for both debt and equity averaging about 45% and preferred stock averaging about 10%.

Capital generated internally should provide funds equivalent to at least 50% of our net construction expenditures, even during periods of major construction programs. However, such a level of internal cash generation can be reached only if we can earn a cash return on CWIP.

The target rate of return on common equity is perhaps the most elusive of our goals. The adequacy of the return on equity is reflected in the market-to-book ratio of our common stock. As long as our stock sells below book value, the equity return obviously is insufficient. Up to now, our efforts have been directed at reducing the spread between the allowed rate of return and what we've earned. Further improvement depends on rate increases and enlightened regulatory policies.



Top: Mile High Stadium lights shine on Monday night football game.

Bottom left: growing air traffic over Denver keeps controller's screen well lighted.

Bottom right: Unique electric applications include laser beam medical operations.

Dividend Policy

The need to sell common stock requires an adequate dividend policy. Because of the serious earnings and cash flow problems of 1979 and 1980, management felt it was imprudent to increase the dividend in those years. The financial improvements of 1981 permitted a 5% increase in the annual dividend rate reflecting the Company's standing commitment to compensate shareholders for their investment.

We would like to have a payout ratio of about 70%, with cash earnings covering the entire amount of the dividend. We would also like to increase the annual rate by a minimum of 4-5%.

Diversification

As part of our long-range strategy to enhance our financial position and our ability to compete for investor capital, we are expanding our opportunities in non-regulated businesses. In 1981, we established Bannock Center Corp., a subsidiary which will be engaged in a variety of non-utility real estate activities in the Denver metropolitan area. The Company's initial investment in this subsidiary is $15 million. We will be reporting our progress in this area as it unfolds in the months and years to come.

We are seeking opportunities to broaden the scope of the subsidiary Fuel Resources Development Co. (Fuelco). Fuelco has functioned primarily as a gas and oil exploration and development company since its inception in 1970. These operations have been more than moderately successful in acquiring natural gas and oil reserves. Fuelco has entered into a letter of intent which could lead to its participation in the business of extracting liquid petroleum products from natural gas.

Fuelco has entered into a joint venture with a West German firm to finance the drilling of 210 wells over a three-year period. The advantage of such a partnership to Fuelco is that it minimizes its investment risk, optimizes the potential for profits and improves its cash flow position.

It is indicative of our continuing interest in oil exploration that Fuelco purchased drilling rights to 28,000 net acres in the western portion of the oil-rich Williston Basin, located in Eastern Montana and the Dakotas. Preliminary seismic testing is underway; exploratory drilling will begin in 1982.

Fuelco has proposed an 80-well drilling program for 1982; about half are exploratory and the balance are development wells. The estimated cost of this program is $16 million. Fuelco will provide 15% and raise the balance of the required funds from partners through various drilling arrangements. Fuelco's share of future drilling activities is expected to increase to 50% by 1985. The overall lease-hold strategy for the next few years is to maintain an inventory of approximately 400,000 net acres and continue to pursue other joint ventures.

Participation in more joint ventures, farm-outs and other appropriate financial agreements and possible entry into the gas products extraction business is part of management's overall strategy to improve Fuelco's financial health. A successful Fuelco will enhance Public Service Company's shareholder equity and its ability to attract investor capital for financing both regulated and non-regulated activities.

Fuelco has staked a claim to a successful future. While Fuelco will be a part of the development of the Rocky Mountain West as an energy center, it will have a profound effect in helping Public Service Company deal with the uncertainties of future utility service.

The Public Service Company that stands at the threshhold of what promises to be a dynamic decade of growth in Colorado is a company at a crossroads. Looking back, we can no longer apply the rationale that guided us so well for so long. We've learned to expect and accept the unexpected. It is with this experience we shall carefully choose our path to the future.

Top left: electricity is firing the processes of Company's industrial customers.

Top center: cultural events symbolize growth and added demands on our utility system.

Right: new skyscraper construction is a common sight in downtown Denver.

Bottom: shopping centers increase energy usage by commercial customers.

Financial Profile

As a regulated public utility, we are obliged to provide all of the electricity and natural gas needs of our customers. As an investor-owned corporation, we have an obligation to provide shareholders with a compensatory return on their investment.

In recent years we have been unable to earn the cost of common equity authorized by the Colorado Public Utilities Commission. Because of that inability we have come to grips with an inconsistency in our fundamental obligations. We cannot deliver increasing amounts of energy in the absence of adequate earnings. This obligation to serve can be undertaken only within the limitations of the financial markets.

The difficulties of the past evolve from inflation, inadequate rate relief and, most of all, from our construction program. We have spent nearly a half billion dollars on the Pawnee plant since 1976. The cost of financing this facility caused a serious financial strain in early 1980. Drastic construction cutbacks and timely rate relief carried us through that financially turbulent period.

Management and shareholders have jointly taken action to avoid a similar situation in the future. Management has taken the position that the Company's financial integrity can no longer be jeopardized by undertaking large capital commitments until there is an apparent ability to raise capital without reducing shareholder assets through the sale of common stock below book value.

Construction Expenditures

Construction expenditures in 1981 were trimmed to $257 million from the original budget of $262 million. This compares with expenditures of $263 million in 1980 and $321 million in 1979. The trend toward lower annual spending results primarily from reduced expenditures on Pawnee, which was in the final phases of completion, and deferment of construction on new generating facilities. We have budgeted $287 million for 1982.

In June, the Company sold 3.5 million shares of common stock to the public at $15 per share. Net proceeds to the Company totaled $50.5 million. We realized an additional $18.7 million of equity through the sale of shares under the Employee Stock Ownership Plan (ESOP) and Dividend Reinvestment Plan (DRP).

Financing in 1981 was completed with the sale in December of $50 million of First Mortgage Bonds. Net proceeds amounted to $49.5 million. The 30-year bonds were sold at a small discount and carry an interest rate of 16¼%.

The Company issued $27.4 million First Mortgage Bonds, Pollution Control Series D, at an interest rate of 13¾%. These bonds, which mature in 2011, were sold to partially refinance $37 million of two-year, 9½% notes issued in early 1980.

Rate Increases

On December 2, 1981, the Company placed into effect new rates for electric, gas and steam services that will increase annual revenues by $120.2 million. These new rates represent an 8.8% overall revenue increase and 64% of the $188.6 million requested in May 1981.

The rate increase request was based on operating and financial data projected for calendar year 1981. In its decision, the CPUC authorized an overall rate of return on Company plant investment of 10.75%. This was an increase from 10.19%, but less than the 12.09% requested. Included in the overall rate of return authorized was a return on shareholders' common equity of 15.7%, up from 15.45%, but less than the 16.29% requested.

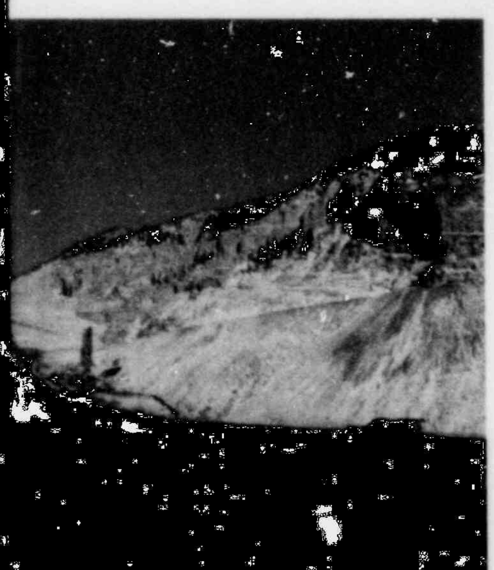
The major portion of the revenues disallowed in our request was $40 million, which related to a 1.1% overall rate of return allowance for attrition. Attrition, in the financial sense, refers to the shortfall between what we actually earn on investment and what the regulatory commission allows us to earn. Attrition has been a major problem for us — and most other utilities — because our actual cost of providing service has risen faster than the revenues we receive from our customers. The primary causes are rapid increases in unrecovered operating costs, large increases in capital costs above those already allowed and faster increases in plant costs — all of which are attributable to high rates of inflation.

Western Slope Gas Company, our wholly-owned natural gas transmission subsidiary, received a $5.8 million increase in annual revenues on November 26. The new rates represent a 3.3% increase and 96% of the amount requested in May.

Public Service Company has pending with the Federal Energy Regulatory Commission an $18.5 million annual revenue increase in electric wholesale rates. The rates are based on a calendar 1982 test year. The rates will go into effect on June 18, 1982 subject to refund pending the conclusion of hearings and a decision.

The Company received approval from the CPUC to revise its electric extension policy, the method we use to recover costs incurred to bring new electric customers onto its distribution system. The new policy will reduce the amount of investment capital the Company must provide to serve those new customers by about $30 million in 1982. The policy applies to all classes of customers. In December, the Company applied for a revised natural gas extension policy that parallels the electric extension policy.

The dynamics of the utility industry have changed dramatically in the past decade. The action we take in the future will be somewhat different from what has been customary. But the goal is still the same: to serve our shareholders and our customers. We intend to serve both well.



Top: the financing of new generating plants is one of the major issues of the 1980s.

Bottom left: oil shale development will influence future financing programs.

Bottom right: construction expenditures are expected to go higher in 1982.

Operations Review

Weather had an uncanny influence on our operating and financial performance during 1981. It was the second warmest year in Denver since record keeping began in 1872; the warmest year was 1934.

Extremely mild temperatures during the January-April and October-December heating seasons caused natural gas sales to drop 13.4%. We had projected a 2% increase. Residential customers used 16.8% less gas in 1981 than in 1980. The number of gas customers increased 3%.

The effect on electric sales was less dramatic. Electric sales increased 1.8%, but this is short of projections of 3.6% based on normal weather conditions and customer usage. Residential customers used 0.3% less electricity than in 1980. Electric customers increased 3.1%.

We estimate that these reductions in energy sales reduced earnings per share by at least 15 cents and possibly closer to 20 cents. We expect that under normal weather conditions in 1982 we can recover the earnings lost in 1981 because of depressed sales.

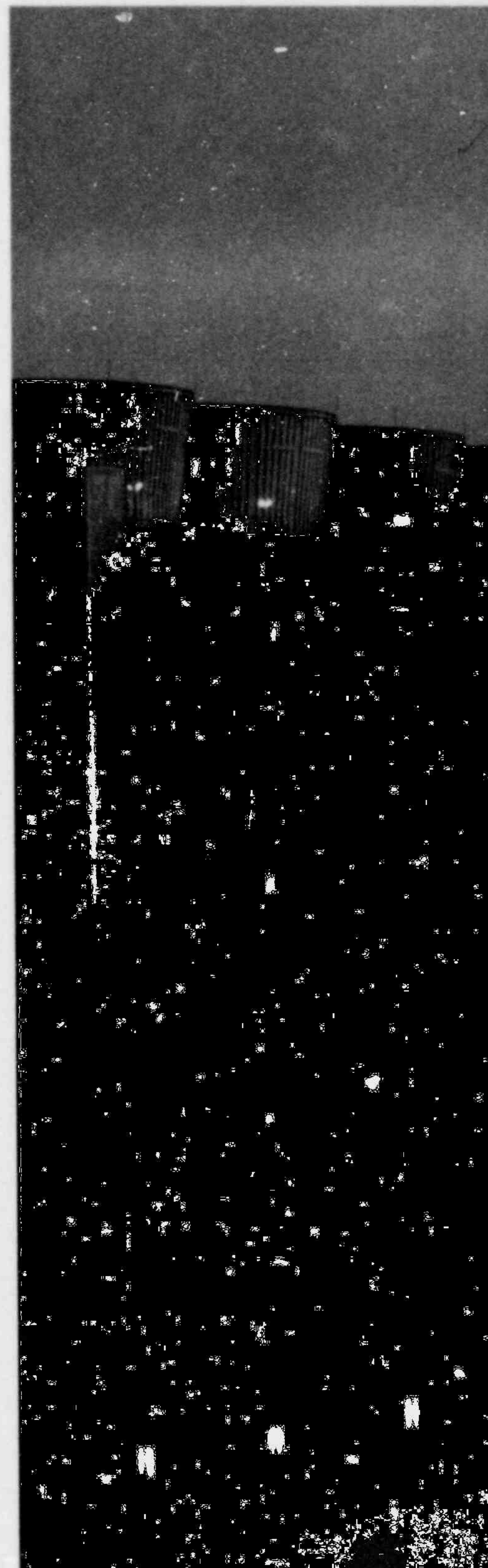
Electric Operations

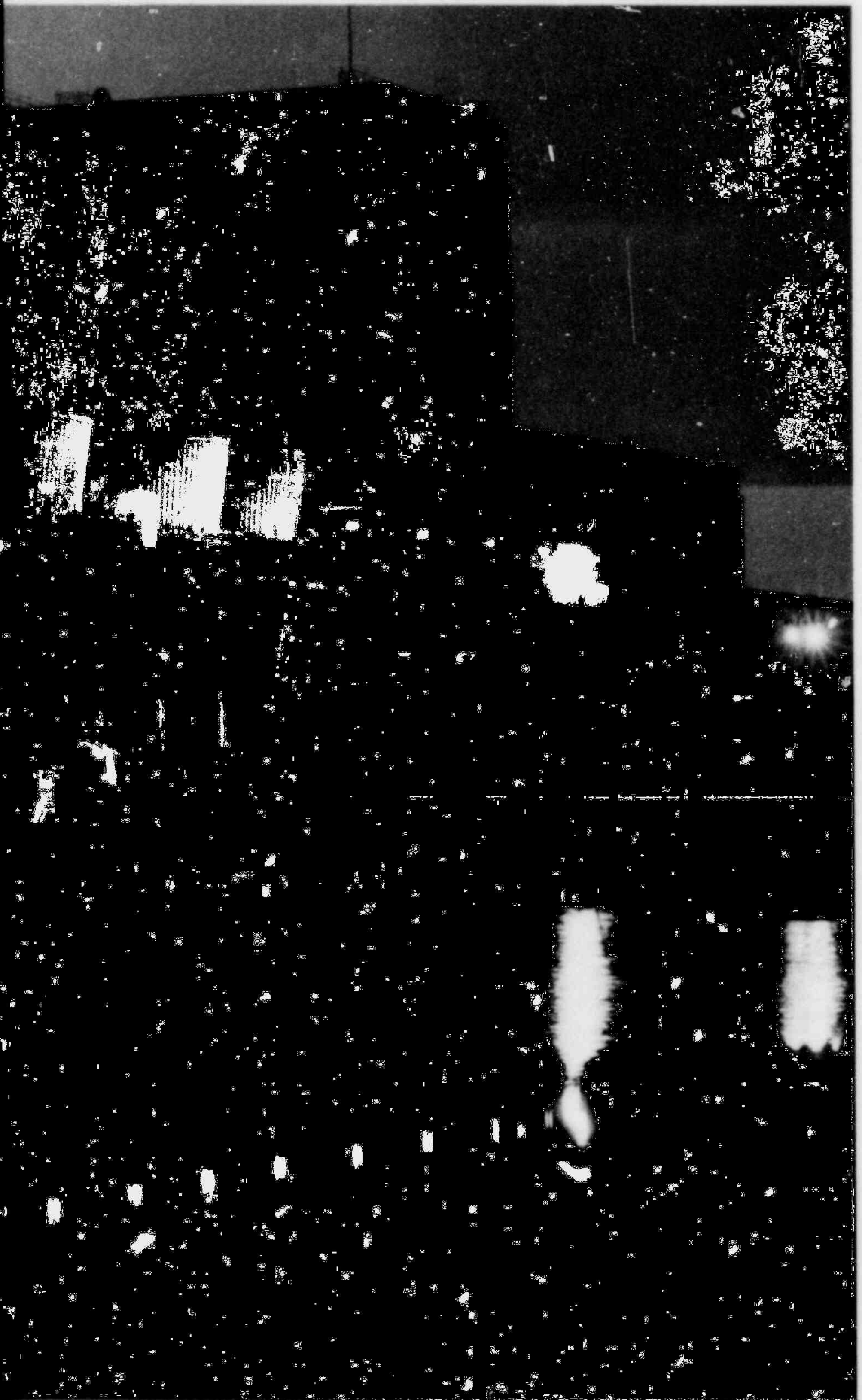
The addition of the Pawnee coal-fired plant in December will have a positive effect on Public Service Company's electric generating system throughout the 1980s. The impact of Pawnee is substantial. Translated into supply, it means we will have enough electric generating capability, coupled with our firm purchased power, to meet all the expected demands within our service territory through at least 1985. In terms of reliability, we will double our reserve margin during peak load periods to about 25% in 1982. The 1981 system peak load of 2,820 megawatts was recorded on July 7. The reserve margin, the difference between total capability including purchased power and load, at that time was 296 megawatts, or 10.5% of the peak demand. This is not adequate to make up for the power that would be lost if one of our larger generating units went out.

Located 90 miles northeast of Denver, the Pawnee unit has a net generating capability estimated at 470 megawatts, bringing the Company's system generating capability to 3,085 megawatts. Tests will be conducted early in 1982 to determine the actual demonstrated net capability. Pawnee is the largest generating unit in Colorado. Total cost of the project, which began in 1976, was $464 million.

Fort St. Vrain

Developments at the Fort St. Vrain Nuclear Generating Station have brightened further the near-term supply outlook. In the Fall, the Company conducted a series of tests that successfully brought the plant to its full power level of 330 megawatts. After the test, the plant was shut down for a planned four-month maintenance period to modify the helium circulator auxiliary systems. The plant will be back in service by March. We will be seeking authority from the NRC to increase the available capacity of the plant above the 200 megawatt limitation.





During the summer, Fort St. Vrain operated at the 70% reactor power level, approximately 200 megawatts of capacity, to help assure the system of a steady supply of electricity during peak demand periods.

Purchased Power

In 1981, we had contracts with neighboring utilities for 573 megawatts of purchased power. This extra power enabled us to have sufficient capability to meet peak demand periods with some reserve margin. The Company has purchased power agreements extending through the 1980s.

Public Service Company and Colorado Ute Electric Association have entered into a preliminary agreement to better coordinate the exchange of power resources between the two companies. Under the terms of a long-term contract currently being negotiated, the schedules of power purchases between the two companies will allow more flexibility in the use of existing generating capacity and timing for the construction of new generating units.

The arrangement recognizes and utilizes seasonal diversity between the loads on each system and incorporates a unique way to schedule power and banked energy. Public Service experiences peak loads in summer; Colorado Ute in winter. We believe that long-term coordinated sale, purchase and banking of electric power will keep overall costs to our customers as reasonable as possible.

The Fort St. Vrain nuclear generating plant was tested at its full power level in 1981.

Coal Usage

Approximately 6.1 million tons of coal were burned at all of the Company's fossil fuel generating plants in 1981, 13.5% more than in 1980. The increased use of coal was partially a result of reduced natural gas usage. Some units were fired with gas until pollution control equipment could be retrofitted, or until additional maintenance was completed.

The addition of Pawnee is expected to increase electric generation from coal to 91.9% in 1982 from 85.3% in 1981. With Pawnee, coal usage in 1982 will increase to an estimated 7.6 million tons.

In a continuing effort to minimize the impact of fuel cost increases on customer bills, and to assure adequate coal supplies, we have negotiated long-term fuel contracts at favorable prices.

Natural Gas Supply

The phased decontrol of natural gas prices legislated in 1978 is achieving the desired result of increasing supply, albeit at higher prices to the consumer. For the first time since 1972, Public Service Company was able to obtain from its suppliers enough gas to meet the backlog of customer demands.

Since 1973, we have operated under a Gas Attachment Scheduling (G.A.S.) Program, which placed new customers on a waiting list and limited new firm customers to an hourly demand of 7,500 cubic feet. This was increased to 20,000 cubic feet in 1981. Although the G.A.S. program is still in effect, we were able to satisfy all applications for residential service. We also were able to provide new or increased service to commercial and interruptible industrial customers.

The supply picture has improved to a point where we are confident of having an adequate gas supply for all new residential customers and small commercial customers in the foreseeable future. There have been no substantial or prolonged weather-related curtailments of interruptible customers during the past two heating seasons. The underground gas storage facilities south of Wiggins, Colorado, known as Roundup, the Leyden Mine near Denver, and Asbury, which is north of Grand Junction, have enabled the Company to store excess gas during the summer months in preparation for delivery during winter peak demand periods. Combined, these three storage facilities are capable of holding a working volume of 9.3 billion cubic feet of gas.

Western Slope Gas Company

Western Slope Gas is a wholly-owned subsidiary operating entirely within Colorado. It is engaged in the purchase, transmission, storage and sale of natural gas. Western Slope provides wholesale service to seven distribution companies, three municipally owned distribution systems and 33 industrial customers. Approximately 77% of its total 1981 sales were for resale, with 81% of the resales going to Public Service Company.

Gas sales in 1981 were affected adversely by warmer-than-normal weather, consumer conservation, and reduced usage of natural gas by Public Service Company for electric generation. Sales for resale declined 9% from 1980 figures. Direct sales dropped nearly 32%.

Revenues increased 10% to $159 million in 1981. This increase stemmed in large part from an 11% increase in the total annual purchased gas expense that Western Slope was allowed to pass on to customers under the Purchased Gas Adjustment provision of its tariff. Net income amounted to $906,000, compared to $2.4 million in 1980.

Western Slope's wellhead reserves at year end totaled 347 billion cubic feet under contracts covering 438 wells connected to its systems. During the year, Western Slope acquired production rights to 39 new wells and connected 56 wells. Western Slope purchased 52.6 million Mcf of natural gas in 1981.

Western Slope entered into two processing agreements to remove hydrocarbon liquids from wellhead supplies. Western will receive a share of the revenues from the sale of these liquids.

Construction expenditures during 1981 amounted to nearly $11 million. Major projects included a transmission line reinforcement of the Craig-Steamboat Springs system, a gathering system extension in the Ignacio field, and a compressor station addition in the Dragon Trail field.

Fuelco

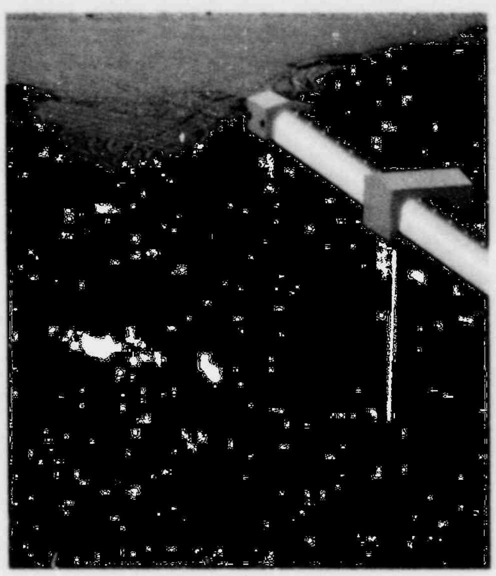
In 1970, Public Service Company organized Fuel Resources Development Co. (Fuelco) as a wholly-owned subsidiary to explore for and develop natural gas reserves. Fuelco has evolved into an oil and gas exploration and production company operating principally in Colorado, Montana, Texas, Utah and Wyoming. On November 30, 1981, Fuelco's net lease holdings totaled 440,445 net acres of which 299,108 net acres were undeveloped.

Western Slope has the right of first refusal on all of Fuelco's natural gas discoveries in Colorado. If Western does not exercise its option to purchase this gas in a timely period, and at competitive rates, Fuelco sells this gas as well as all crude oil and other gas to the best available market.

Top: this computer bank is the heart of the Pawnee electric generating plant.

Bottom left: residential electric customers grew in number but conserved more.

Bottom right: coal continues to be the primary fuel in generating electricity.



Gross operating revenues for 1981 increased 3.7% to $9.5 million from $9.2 million in 1980. Natural gas sales were $5.26 million (55.4%), crude oil sales were $2.97 million (31.2%) and other income was $1.27 million (13.4%). Of the total natural gas sales, $1.95 million, or 37%, were made to Western Slope Gas Company.

Although gas sales volumes decreased 5.3% to 2,517,727 Mcf in 1981, gas revenues increased by 20.9%. This increase in revenue was caused by a 27% increase in the average unit price of gas, or $2.09 per Mcf compared with $1.64.

Oil sales volumes declined 7.3% to 84,238 barrels. The decline resulted from fewer of the new wells drilled having high initial production and the normal production decline in older wells. The average unit price per barrel, before the Windfall Profits Tax, increased 11.8% to $35.23 from $31.51 in 1980, and resulted in a 3.6% increase in oil revenues.

Fuelco has entered into an agreement with Internationaler Energie Fonds GmbH (IEF) which will continue to participate financially in a specified number of wells to be drilled by Fuelco. Fuelco has also entered into a farmout agreement with Beartooth Oil and Gas Company. Beartooth will drill and complete 26 wells in Western Colorado.

These agreements will better utilize Fuelco's cash flow by providing more opportunities for additional joint ventures while minimizing future exploratory and development risks.

Operating expenses decreased 11.3% due primarily to significantly reduced dry hole costs and lease and well impairments.

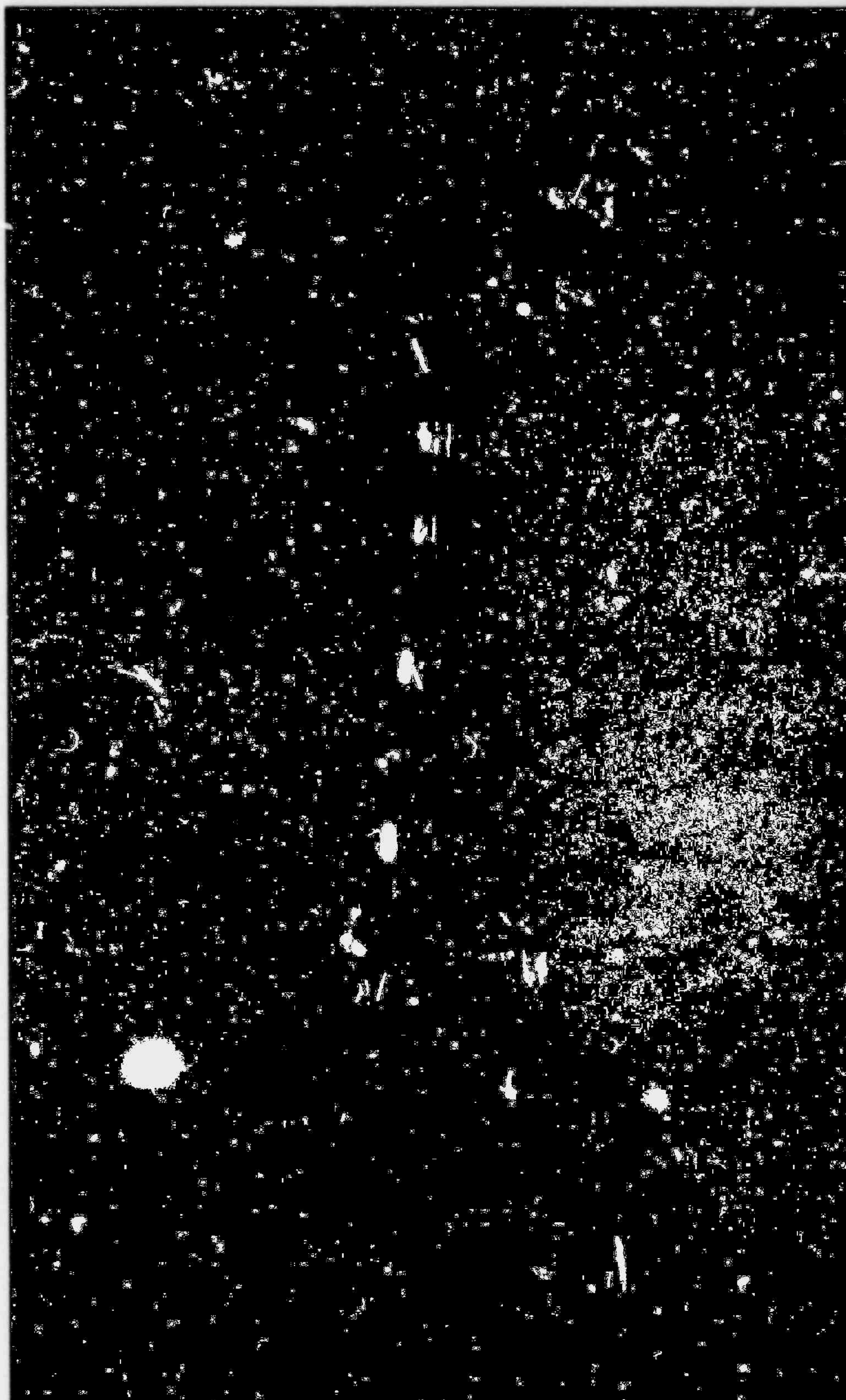
Windfall Profits Taxes for 1981 increased primarily because the full year production was subject to the tax. Last year only nine months' production was subject to the Windfall Profits Tax. Other segments of expenses had moderate increases. Net interest expense for 1981 decreased 1% for the year.

During 1981, Fuelco's capital expenditures were $5.1 million compared with $5.3 million in 1980. Capital expenditures in 1982 are budgeted at $8.9 million.

At the end of 1981, Fuelco had $29.6 million invested in natural gas and crude oil wells with proven developed net revenue interest reserves of 116.3 Bcf of gas and 801,700 barrels of oil and proven undeveloped net revenue interest reserves of gas and oil were 73.2 Bcf and 80,700 barrels respectively.

Fuelco had a working interest in 313 wells at the end of 1981. 203 of these wells are producing, 37 are under contract for imminent hookup and 73 are completed and waiting for pipeline hookup while negotiations continue on sales contracts. Fuelco also has royalty interests in 91 wells, a portion of which will convert to a working interest when the operator has recovered his costs out of production.

Revenues did not increase as projected due to warm weather and conservation, resulting in a smaller than expected profit of $11,683. This is a significant improvement from an $892,326 loss in 1980. Our goal for 1982 is to produce stronger earnings, but it would still have a minimal effect on the consolidated earnings of Public Service Company. The longer-term objective is to become financially self-sufficient within three years.



Fuelco is diversifying the way it participates in oil and gas exploration programs.

Shareholder Information

The Company's common stock ($5 par value) is listed for trading on the New York and Midwest Stock Exchanges under the ticker symbol "PSR." Quotes may be obtained in daily newspapers where the common stock is listed as "PSvCo" in the New York Stock Exchange listing table. During 1981, 13,204,400 shares were traded, an average daily volume of 52,191. There were 13,034,200 shares traded in 1980, an average daily volume of 51,519. Shares outstanding at December 31, 1981 were 44,895,939 compared to 39,989,753 outstanding at December 31, 1980. There were 72,427 common shareholders of record and 6,084 preferred shareholders of record at year-end 1981 compared with 71,409 common shareholders and 6,237 preferred shareholders at year-end 1980.

Three series of Cumulative Preferred Stock are actively traded. The 4¼% series ($100 par value) is traded under unlisted trading privileges on the American Stock Exchange. The 7.15% series ($100 par value) and 8.40% series ($25 par value) are listed on the New York Stock Exchange. All other series of cumulative preferred stock are not actively traded, and market prices are not published.

Dividend Reinvestment Plan

The Company's Automatic Dividend Reinvestment and Common Stock Purchase Plan (DRP) provides preferred and common shareholders with an economical and convenient method for purchasing additional shares of the common stock of the Company without the payment of brokerage commissions or service charges.

Beginning January 1, 1982, cash dividends reinvested by an eligible individual in additional shares of the Company's common stock through the DRP will be eligible for certain tax benefits provided by the Economic Recovery Tax Act of 1981 (ERTA).

Dividends reinvested through the DRP are used to purchase common stock at 95% of the average of the high and low sale prices of the common stock as reported on the consolidated tape on each investment date, or if no trading occurs on such date, the next preceding date on which trading occurs. In addition, preferred and common shareholders whose shares are registered in names other than their own may participate in the DRP for the reinvestment of dividends, provided the broker or fiduciary who holds such stock in nominee name is willing to participate in the DRP.

Shareholders of record who are participants in the DRP also can make stock purchases monthly for cash in amounts of not less than $10 per payment and not more than a total of $5,000 each month. The price to be paid for each share of stock purchased with such optional cash payments will be 100% of the market price on each investment date.

At year-end 1981, there were 20,927 participants, an increase of 1,651 or 8.6% compared to year-end 1980. A total of $11,984,570 in reinvested dividends and optional cash payments was applied to purchase 895,405 new shares at an average cost of $13.38.

The effects of ERTA are already being demonstrated in the Company's DRP. As of February 1, 1982, there are 21,285 participants (29.4% of common shareholders) reinvesting dividends on 9,574,000 shares (21.3% of outstanding common shares). This represents an increase of 46.8% over the shares participating on February 1, 1981.

A prospectus describing the DRP and enrollment information can be obtained from the Shareholder Services Department by writing or by calling Area Code (303) 571-7514.

Transfer Agents

The Company's principal transfer agent and registrar is Morgan Guaranty Trust Company of New York (Morgan Guaranty). Shareholders who are transferring either preferred or common stock may do so by forwarding the certificates being transferred to Morgan Guaranty. Such certificates should have the stock assignment form on the reverse side of the certificate properly filled in, including the Social Security number of the party to whom the stock is being transferred, and the signature of the person or persons transferring the stock "guaranteed."

The person or persons transferring the stock should endorse the assignment form exactly as the stock is registered. The signature(s) of the transferor must be guaranteed either by a commercial bank or a brokerage firm that is a member of one of the major stock exchanges.

For added convenience, the Company has two co-transfer agents, United Bank of Denver, N.A., Denver, Colorado, and Bank of America National Trust and Savings Association, San Francisco, California, where the Company's preferred and common stock may be sent for transfer.

United Bank of Denver, N.A., has announced its intent to eliminate its stock transfer function by mid-year 1982. However, United Bank of Denver and Bank of America have reached a tentative agreement whereby Bank of America will maintain a Denver transfer agency office. Therefore, a Denver office still will be available after mid-year 1982 for the transfer of stock.

Stock Registration

When stock is purchased, the purchaser has the choice of leaving the stock with the broker or having the certificate delivered to the purchaser. If the stock is left with the broker, it is generally left in the brokerage firm's name. This stock is referred to as "street name" stock. The purchaser is generally referred to as the beneficial owner.

Shareholders who elect to take physical possession of their stock receive a certificate or certificates representing the number of shares purchased. The stock is registered in the shareholder's name and the shareholder becomes a shareholder of record on the Company's books.

Safekeeping of Certificates

When stock certificates are received, it is recommended that the certificates be safeguarded by placing them in a secure place such as a bank safety deposit box. A separate record of each certificate should be maintained including the certificate number, the purchase date, the date of issue, the amount paid and the registration.

Dividends

The Company pays regular quarterly dividends on its preferred stock on March 1, June 1, September 1, and December 1 of each year. Dividends on common stock, as declared by the Board of Directors, are generally payable on the first day of February, May, August and November of each year.

Dividends paid on stock held in "street name" are paid to the holder of record, generally a brokerage firm or bank nominee. The dividends are then redistributed to beneficial owners by the brokerage firm or bank in accordance with the beneficial owner's instructions.

Shareholders of record receive dividends directly from the transfer agent unless such shareholder has elected to reinvest dividends through the Company's DRP. Shareholders who are DRP participants receive a statment of account 15 to 20 days after each investment date.

Lost or Stolen Certificates

If a stock certificate is lost or stolen, notification should be sent immediately to the transfer agent so a "stop" can be placed on the missing certificate. The letter should contain as much information as possible describing the certificate; in particular, the certificate number, the date issued and the registration. Once a "stop" has been placed on the missing certificate, the transfer agent will send an affidavit that must be filled out, signed, notarized and returned before a replacement certificate can be issued. An indemnity bond for the lost certificate is also required. The cost is about 3% of the current market value of the missing certificate, calculated at the time the indemnity bond is issued.

Information regarding lost or stolen certificates should be sent to Morgan Guaranty Trust Company of New York, Estoppel Department, 30 West Broadway, New York, New York 10015.

Duplicate Mailings

Those shareholders who hold stock in more than one registration receive corporate mailings for each account. On the inside of the back cover of the Annual Report is a card that can be used to eliminate duplicate mailings. For those accounts which require no report mailings, merely check the appropriate box on the card, fill in the shareholder account number and name, as listed on the Annual Report mailing label, and drop the card in the mail.

The accompanying tables show the ranges of closing stock prices as shown on the consolidated tape and dividends paid on the common and preferred stock issues by quarter for 1981 and 1980.

Common Stock

Quarter	Year	4th	3rd	2nd	1st
1981					
High	15	15	14⅞	15	15
Low	12¾	12¾	12¾	13½	13⅞
Last Trade	14¼	14¼	13⅜	14½	14½
Dividends Declared	1.68	.42	.42	.42	.42
Dividends Paid	1.66	.42	.42	.42	.40
1980					
High	15¼	14⅞	14⅞	15¼	14¾
Low	11⅛	12	12⅜	11⅛	11⅛
Last Trade	14¼	14¼	13⅝	14¾	11⅛
Dividends Declared	1.60	.40	.40	.40	.40
Dividends Paid	1.60	.40	.40	.40	.40

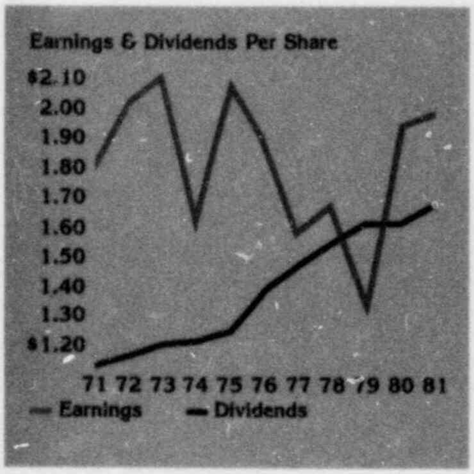
Cumulative Preferred Stock

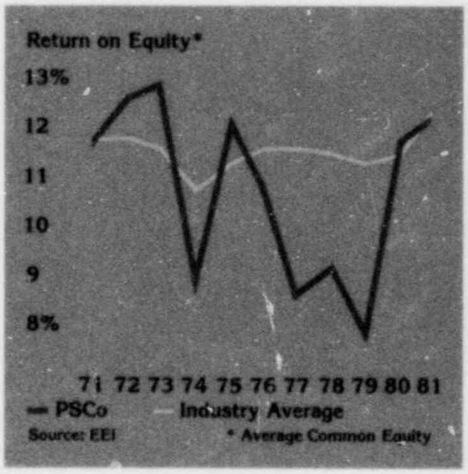
Quarter	4th	3rd	2nd	1st
4¼ Series				
1981 High	31½	30½	32¼	34
Low	27	27½	29½	31
1980 High	37½	39	39	36½
Low	26	34⅛	29½	28⅞
7.15% Series				
1981 High	49½	50	50	55
Low	42	42⅛	48	51
1980 High	59	69	68	61¼
Low	55	57	59	59
8.40% Series ($25)				
1981 High	15¾	15¼	15¾	16
Low	13½	13½	13⅜	14¼
1980 High	17	20	20½	18¾
Low	13⅞	15⅞	14¼	14¼

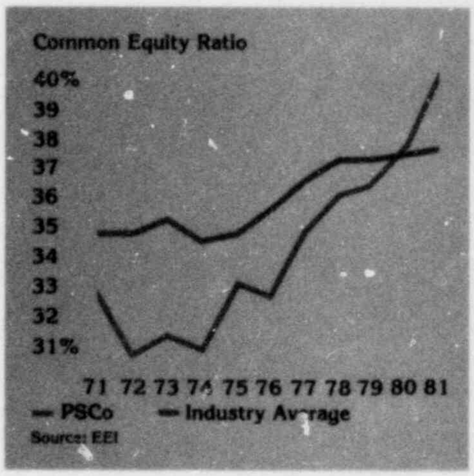
Summary of Operations

Selected Financial Data and Ratios

	Year Ended December 31,						
	1981	1980	1979	1978	1977	1976	1971
	(Thousands of Dollars)						
Operating Revenues:							
Electric	$ 742,104	640,749	507,587	421,732	362,062	322,102	$145,977
Gas	582,434	502,919	410,537	303,300	246,059	197,549	90,572
Other	11,633	11,976	8,386	4,746	5,178	2,503	1,522
Total	1,336,171	1,155,644	926,510	729,778	613,299	522,154	238,071
Operating Expenses:							
Fuel used in generation	171,657	184,073	176,413	117,491	104,982	86,711	24,965
Gas purchased for resale	462,291	388,852	310,129	224,840	176,193	127,788	44,299
Purchased power	113,235	91,414	29,425	22,722	4,738	4,361	2,887
Other operating expenses	192,639	168,114	162,858	132,647	105,434	87,931	48,053
Maintenance	49,735	46,646	37,092	28,249	27,220	23,241	11,451
Depreciation	73,643	61,594	55,990	49,541	46,133	43,196	24,068
Taxes (other than income taxes)	64,001	40,433	38,033	35,424	44,346	40,048	24,374
Income taxes	67,914	52,190	26,826	25,601	16,100	21,232	10,265
	1,195,115	1,033,316	836,766	636,515	525,146	434,508	190,362
Operating Income	141,056	122,328	89,744	93,263	88,153	87,646	47,709
Other Income and Deductions	23,464	21,832	13,162	6,196	2,902	7,634	5,174
Interest Charges	63,765	59,133	47,097	41,758	39,918	40,621	21,412
Net Income	100,755	85,027	55,809	57,701	51,137	54,659	31,471
Preferred dividend requirements	16,661	15,020	13,536	13,536	13,536	10,784	3,669
Earnings Available for Common Stock	$ 84,094	70,007	42,273	44,165	37,601	43,875	$ 27,802
Earnings Per Average Share	$1.97	1.92	1.35	1.66	1.57	1.89	$1.80
Dividends Per Share							
Paid	$1.66	1.60	1.60	1.49½	1.46	1.34	$1.12
Declared	$1.68	1.60	1.60	1.53	1.46	1.38	$1.12
Common Stock Shares Outstanding (000):							
Average	42,728	36,412	31,225	26,572	23,976	23,240	15,463
Year-end	44,896	39,990	32,326	29,250	25,884	23,290	15,477

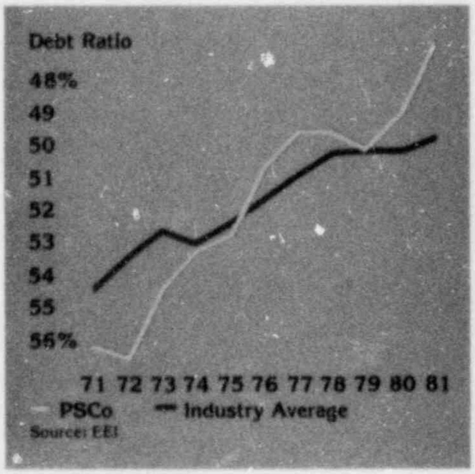


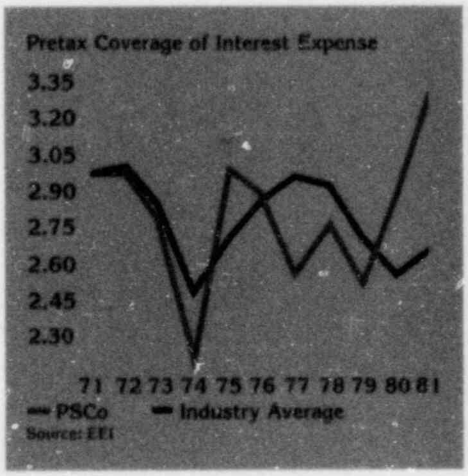


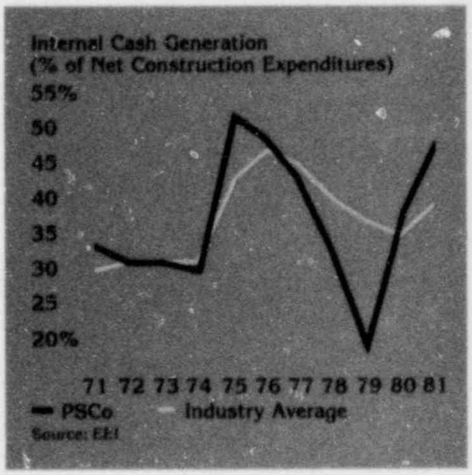


Financial Data

Financial Data	1981	1980	1979	1978	1977	1976	1971
Total Assets (millions)	$2,431	2,216	2,011	1,746	1,576	1,465	$847
Long-term Debt (millions)	$ 866	840	767	711	647	602	$417
Preferred Stock (millions):							
Subject to mandatory redemption	$ 89	89	64	64	64	64	—
Not subject to mandatory redemption	$ 140	140	140	140	140	140	$ 80
Common Equity (millions)	$ 736	656	555	516	460	411	$242
Capitalization Ratios — Year-End:							
Long-term debt (incl. debt due within 1 yr.)	45.8%	48.9	48.3	49.0	49.2	50.9	54.9%
Short-term borrowings	3.2%	0.5	3.9	1.5	1.3	0.5	2.7%
Preferred stock	12.1%	13.1	12.9	14.1	15.2	16.1	10.5%
Common equity	38.9%	37.5	34.9	35.4	34.3	32.5	31.9%
Total Capitalization (millions)	$1,895	1,751	1,591	1,4[illegible]3	1,341	1,265	$760
Rates of Return Earned:							
Total capitalization (Oper. Income)	7.7%	7.0	5.6	6.4	6.6	6.9	6.3%
Avg. common equity (Net to Common)	12.1%	11.6	7.9	9.1	8.6	10.8	11.7%
Pretax Coverage of Interest Expenses	3.24	2.86	2.50	2.74	2.54	2.87	2.94
Payout Ratio on Dividends Paid	84.3%	83.3	118.5	90.1	93.0	70.9	62.2%
Book Value Per Share — Year-End	$16.39	16.40	17.18	17.63	17.77	17.63	$15.64
Market Price Per Share—Year-End	$14.25	14.25	13.38	16.75	18.88	19.00	$23.75
Dividend Yield — Year-End	11.8%	11.2	12.0	9.6	7.7	7.7	4.7%
Number of Employees — Year-End	6,424	6,145	6,310	6,082	5,977	5,701	5,083

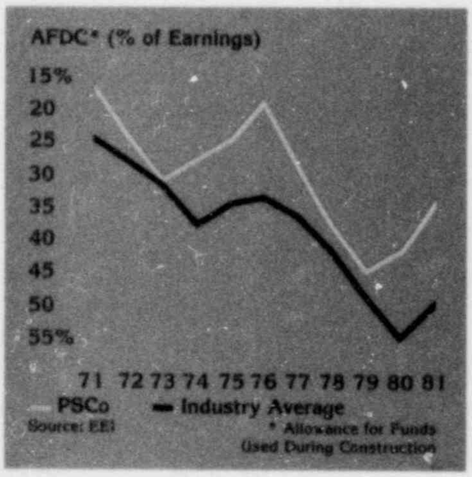


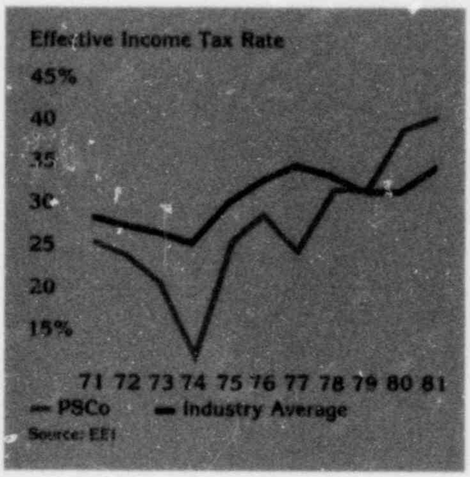


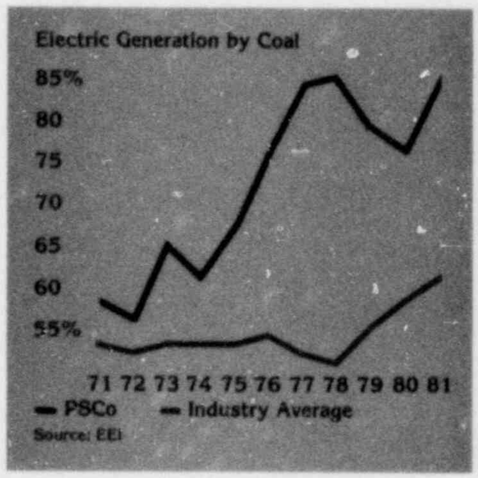


Electric Service Statistics

Electric Service Statistics	1981	1980	1979	1978	1977	1976	1971
Kilowatt-Hour Sales (millions)	15,473	15,194	14,659	13,754	12,877	11,890	7,928
% Change	1.8%	3.6	6.6	6.8	8.3	5.1	9.2%
Customers (000)	846.1	820.5	794.5	764.8	733.0	676.1	528.7
% Change	3.1%	3.3	3.9	4.3	8.4	2.8	5.7%
Avg. Annual Residential Kwh Usage	5,734	5,937	5,913	5,724	5,520	5,480	5,043
% Change	(3.4)%	0.4	3.3	3.7	0.7	1.7	4.5%
Avg. Residential Revenue Per Kwh	5.74¢	5.12	4.19	3.75	3.60	3.50	2.54¢
% Change	12.1%	22.7	11.7	4.2	2.9	4.5	(1.6)%
Average Annual Revenue Per Residential Customer	$329	304	248	215	199	192	$128
% Change	8.3%	22.7	15.4	8.0	3.7	6.0	3.1%
Net Effective Capability at Time of Peak—Kilowatts	3,116	3,072	2,743	2,594	2,492	2,484	1,888
Net Firm System Peak Load (Kw)	2,820	2,776	2,642	2,559	2,437	2,237	1,538
% Change	1.6%	5.1	3.2	5.0	9.0	6.1	11.7%
Reserve Margin at Time of Peak	10.5%	10.7	3.8	1.4	2.3	11.1	22.8%
Generation by Class of Fuel:							
Coal	85.3%	76.1	79.2	85.0	83.8	75.5	57.5%
Natural Gas	8.4%	17.8	17.6	12.1	13.5	21.6	41.0%
Oil	0.3%	0.8	1.8	2.9	2.7	2.9	1.5%
Nuclear	6.0%	5.3	1.4	—	—	—	—
Avg. Cost Per Unit of Fuel (Dollars):							
Coal — Ton	$21.84	18.81	16.60	13.90	12.31	10.24	$6.15
Natural Gas — Mcf	$ 3.12	2.68	2.00	1.30	1.03	0.79	$0.23
Oil — Barrel	$39.96	26.37	17.19	13.03	15.20	14.59	$3.88
Avg. Fuel Cost Per MMBTU	$1.23	1.30	1.10	0.85	0.75	0.67	$0.28

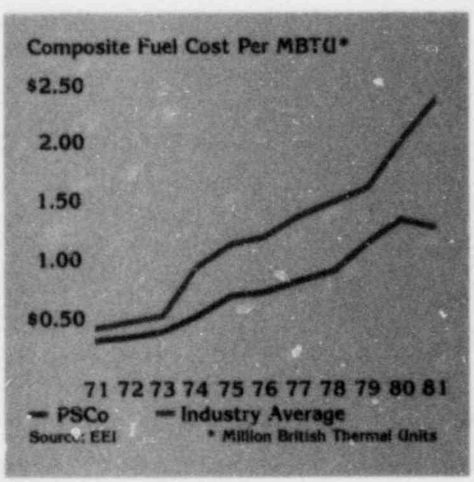


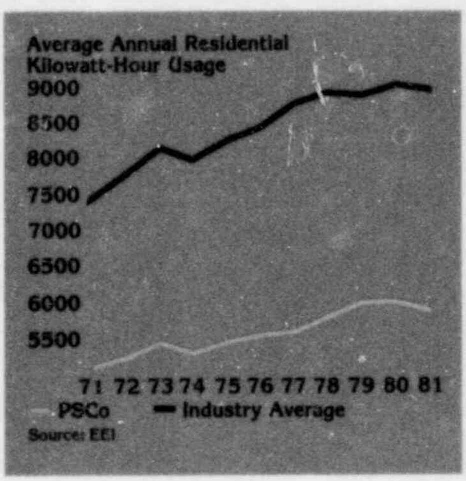


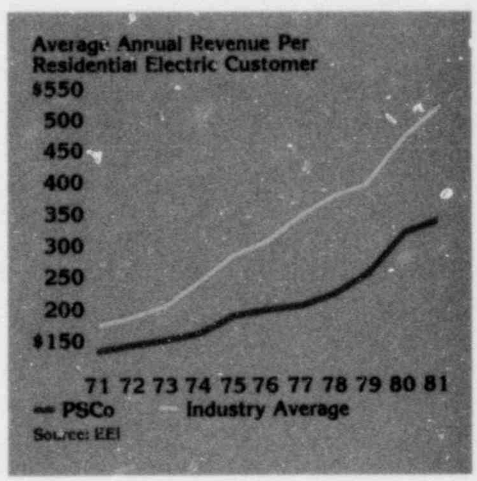


Natural Gas Service Statistics

	1981	1980	1979	1978	1977	1976	1971
Bcf Gas Sales	176.1	203.3	213.3	206.7	198.3	209.7	192.1
% Change	(13.4)%	(4.7)	3.2	4.3	(5.4)	(2.7)	4.0 %
Customers (000)	701.3	680.6	658.2	633.6	609.5	589.6	482.3
% Change	3.0 %	3.4	3.9	4.0	3.4	2.5	5.1 %
Average Annual Residential Mcf Usage	112.9	140.1	157.3	151.2	146.3	160.3	185.8
% Change	(19.4)%	(10.9)	4.0	3.3	(8.7)	(7.0)	(0.1)%
Annual Heating Degree Days	4,570	5,768	6,396	6,006	5,195	5,755	6,269
% Change	(20.8)%	(9.8)	6.5	15.6	(9.7)	(7.7)	1.7 %
Average Residential Revenue Per Mcf	$3.48	2.70	2.08	1.64	1.43	1.11	$0.62
% Change	28.9 %	29.8	26.6	14.8	29.1	14.8	3.2 %
Average Annual Revenue Per Residential Customer	$393	378	327	249	209	178	$115
% Change	3.9 %	15.4	31.7	18.7	17.8	6.9	3.1 %
Daily Availability — (MMcf)	1,457	1,425	1,371	1,304	1,275	1,282	1,059
Maximum Peak-Day Sendout (MMcf)	1,278	1,246	1,143	1,160	1,129	1,161	944
% Change	2.6 %	9.0	(1.5)	2.7	(2.8)	8.8	9.3 %







Consolidated Financial Information

Report of Management

The accompanying financial statements of Public Service Company of Colorado and subsidiaries have been prepared by Company personnel in conformity with generally accepted accounting principles consistent with the Uniform System of Accounts of the Federal Energy Regulatory Commission. The integrity and objectivity of the data in these financial statements are the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the financial statements.

The Company maintains and enforces a system of internal accounting controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records. This system includes a program of internal audits to assure management that proper procedures and methods of operation are used to implement the plans, policies and directives of management.

The accounting and internal control procedures of the Company are reviewed by the Audit Committee of the Board of Directors. The Committee, which is composed of directors who are not employees of the Company, meets regularly with the Company's management, the internal audit staff and the independent accountants.

The accompanying financial statements have been examined by Arthur Young & Company, independent accountants, whose report is on page 47.

D D Hock

D. D. Hock
Vice President and
Chief Accounting Officer

R. F. Walker

R. F. Walker
President and
Chief Executive Officer

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

The following factors, which may not be indicative of future operations or earnings, have had a significant effect upon the results of operations during 1981, 1980, and 1979.

Results of Operations

Operating revenues continued to increase significantly each year primarily as a result of increases in base rates and customers and the recovery of increased cost of fuel used in generation and gas purchased for resale through the adjustment clauses of both the electric and gas tariffs. Additionally, in 1981 a portion of the increase in base rate revenue was due to an order from the Public Utilities Commission of the State of Colorado (CPUC), requiring that franchise taxes be accounted for as a component of revenue and expense rather than surcharged on customers' bills and recorded as tax collections.

The following table sets forth the amounts by which the electric and gas revenues during the last three years exceeded the revenues for the preceding year, together with the estimated increases attributable to the major factors.

	1981	1980	1979
	(Millions of Dollars)		
Electric revenues			
Base rate increases	$ 61.2	$ 52.4	$ 13.6
Energy cost adjustment	15.6	59.8	39.1
Sales volume and other changes	24.6	21.0	27.2
Net increase	$101.4	$133.2	$ 85.9
Gas revenues			
Base rate increases	$ 11.1	$ 10.8	$ 10.1
Gas cost adjustment	90.0	99.7	84.7
Sales volume and other changes	(21.6)	(18.1)	12.4
Net increase	$ 79.5	$ 92.4	$107.2

The increases (decreases) in operating expenses were as follows:

	1981	1980	1979
	(Millions of Dollars)		
Fuel used in generation	$ (12.4)	$ 7.7	$ 58.9
Gas purchased for resale	73.4	78.7	85.3
Purchased power	21.8	62.0	6.7
Other operating expenses	24.5	5.3	30.2
Maintenance	3.1	9.5	8.8
Depreciation	12.1	5.6	6.5
Taxes (other than income taxes)	23.6	2.4	2.6
Income taxes	15.7	25.4	1.2
Net increase	$161.8	$196.6	$200.2

The increase in operating expenses is primarily the result of increases in the cost of gas purchased for resale and the quantity of power purchased, and increases in the cost of fuel used in generation in 1979 and 1980. Fuel used in generation decreased in 1981 mainly as a result of the availability of natural gas for use as fuel in combustion turbines rather than the more expensive fuel oil.

Other operating expenses increased due to annual wage increases and normal system expansion. Taxes (other than income taxes) increased due to the order from the CPUC, referred to above, requiring a change in the accounting for franchise taxes.

The increase in net income in 1981 as compared to prior years primarily resulted from base rate increases granted in May 1980 and November 1980. The increases in long-term debt, preferred and common stock and the corresponding increase in the number of average shares of common stock outstanding is the result of the need for continued financing to support the Company's construction program. The changes in earnings per average share of common stock outstanding are a result of the changes in net income and increases in the number of shares outstanding.

Liquidity and Capital Resources

The Company and its subsidiaries estimated, at December 31, 1981, the cost of their construction program, including Allowance for Funds Used During Construction (AFDC) and other capital requirements, in 1982, 1983, and 1984 to be as follows:

	1982	1983	1984
	(Thousands of Dollars)		
Company:			
Electric			
Production	$106,567	$112,858	$209,495
Transmission	20,979	58,464	52,282
Distribution	51,406	52,751	51,679
Other	391	295	318
Gas	25,275	26,560	25,210
General	29,839	21,740	24,758
Subtotal	234,457	272,668	363,742
Subsidiaries	52,818	29,977	28,294
Total construction	287,275	302,645	392,036
Less: AFDC	9,136	18,505	30,852
Add: Sinking funds and debt maturities	2,506	20,372	51,583
Total capital requirements	$280,645	512	$412,767

The Company's objectives for the financing of these capital requirements include: internal generation of at least one-half of the funds required; maintenance of a sound capitalization structure consisting of not less than 40% common stock, not more than 45% long-term debt and the balance in preferred stock; and the maintenance of high credit ratings for its securities.

At December 31, 1981, the Company and its subsidiaries estimated that their 1982-1984 capital requirements would be met with funds provided from the following sources:

	1982	1983	1984
	(Thousands of Dollars)		
External	$ (31,146)	$ 7,599	$179,870
Internal	311,791	296,913	232,897
Total sources	$280,645	$304,512	$412,767

For 1982, the Company and its subsidiaries anticipate raising external funds in approximately the following amounts: (1) $24.6 million from the sale of common stock through the Company's Automatic Dividend Reinvestment and Common Stock Purchase Plan and its Employee Stock Ownership Plan; (2) $13.0 million from a construction loan to be entered into by 1480 Welton, Inc. early in 1982, the proceeds of which are to be used by 1480 Welton, Inc. during 1982 for the construction of an office building which will be leased to the Company; (3) subsidiary unsecured long-term debt as follows: $2.6 million of Fuel Resources Development Co. debt, $7.0 million of Western Slope Gas Company debt, and $5.0 million of Cheyenne Light, Fuel and Power Company debt; and (4) $0.2 million from pollution control revenue bond proceeds held in trust. The Company and its subsidiaries expect to increase their net short-term investments and decrease their net short-term borrowings by a total of $83.5 million in 1982. The net reduction in short-term indebtedness of $83.5 million, which is partially due to net proceeds from financings of $52.4 million, results in the negative source of external funds presented in the chart above. These financing plans are subject to change depending on market and business conditions and changes in the construction plans of the Company and its subsidiaries, if any. Plans for sales of securities beyond 1982 have not been formalized at this time.

The construction estimates shown above are subject to continuing review and adjustment. Actual expenditures may vary from such estimates due to factors such as changes in business conditions, environmental requirements, availability and cost of labor and materials and other costs. In addition, if the Company's objectives for the financing of its construction expenditures in future years cannot be attained without significant common equity dilution from the sale of common stock below book value, such estimated construction expenditures will be reduced. Under such circumstances, construction will be limited to commitments previously made, such as the installation of pollution control equipment required to bring the Company's facilities into compliance with various governmental standards, regulations or variances and to the maintenance of existing facilities.

The Company's Indenture permits the issuance of additional first mortgage bonds to the extent of 60 percent of the value of net additions to the Company's utility property, provided net earnings before depreciation, taxes on income and interest expense for a recent twelve month period are at least 2.5 times annual interest requirements on all bonds to be outstanding. The amount of net additions at December 31, 1981, would permit (and the net earnings test would not prohibit) the issuance of approximately $292,000,000 of additional bonds at an assumed annual interest rate of 16.50%.

The Company's Restated Articles of Incorporation prohibit the issuance of additional preferred stock without preferred shareholder approval, unless the gross income available for the payment of interest charges for a recent twelve month period is at least 1.5 times the total of (1) the annual interest requirements on all indebtedness to be outstanding for more than one year and (2) the annual dividend requirements on all preferred stock to be outstanding. At December 31, 1981, gross income available under this requirement would permit the Company to issue approximately $458,000,000 of additional preferred stock at an assumed annual dividend rate of 14.0% (assuming no additional long-term debt is issued).

The Company's Restated Articles of Incorporation prohibit, without preferred shareholder approval, the issuance or assumption of unsecured indebtedness, other than for refunding purposes, greater than 15% of the aggregate of (i) the total principal amount of all bonds or other securities representing secured indebtedness of the Company, then outstanding, and (ii) the total of the capital and surplus of the Company, as then recorded on its books. At December 31, 1981, the Company had outstanding unsecured indebtedness, including subsidiary indebtedness which is guaranteed by the Company, in the amount of $91,130,000. The maximum amount permitted under this limitation was $267,153,434 at December 31, 1981.

Arrangements for bank lines of credit totaled $117,597,000 and arrangements for bankers' acceptance facilities amounted to $10,000,000 at December 31, 1981. The entire amount of these arrangements was available to the Company and its subsidiaries at December 31, 1981.

Impact of Inflation and Changing Prices

The financial statements are prepared in accordance with generally accepted accounting principles and are based on the results of business transactions as recorded in actual amounts of dollars at the time of each transaction. However, during periods of rapidly changing prices, these financial data based on actual historical costs tend to become distorted and fail to reflect real economic costs or value. For example, in capital intensive industries, such as the utility industry, the cost of maintaining productive capacity has been particularly affected by significant long-term inflation. Very simply, depreciation expense on utility property, plant and equipment which is charged against current earnings for assets acquired in the past does not reflect the inflated cost of acquiring similar assets at current prices. As a result, higher profits may be reported on a continuing basis with no accompanying gain in real purchasing power or economic value. (See Note 12 of Notes to Consolidated Financial Statements)

Consolidated Balance Sheet

December 31, 1981, and 1980
Public Service Company of Colorado and Subsidiaries

Assets

	1981	1980
	(Thousands of Dollars)	
Property, Plant and Equipment, at cost:		
Electric	$2,063,817	$1,512,304
Gas	473,066	441,747
Steam and other	26,609	9,696
Common to all departments	98,868	90,652
Construction in progress	74,347	451,788
	2,736,707	2,506,187
Less accumulated provision for depreciation	661,834	593,879
	2,074,873	1,912,308
Nuclear fuel, less accumulated provision for amortization (1981—$3,509; 1980—$1,980) (Notes 1 and 11)	14,277	8,266
	2,089,150	1,920,574
Investments, at cost	564	320
Current Assets:		
Cash	20,293	[illegible],909
Temporary cash investments	4,502	3,951
Accounts receivable, less provision for uncollectible accounts (1981—$2,353; 1980—$2,131)	129,590	122,840
Notes receivable	259	317
Fuel inventory, at average cost	65,704	60,679
Materials and supplies, at average cost	46,307	39,833
Cost of gas delivered but not billed to customers	37,143	30,693
Gas in underground storage, at cost (LIFO)	12,728	8,528
Prepaid expenses	3,832	3,852
Total Current Assets	320,358	279,602
Deferred Charges:		
Debt expense (being amortized)	8,034	7,415
Other	12,862	8,459
	20,896	15,874
Total Assets	$2,430,968	$2,216,370

See accompanying notes.

Capital and Liabilities

	1981	1980
	(Thousands of Dollars)	
Common Equity:		
Common stock (Note 2)	$ 585,864	$ 514,566
Retained earnings	150,166	141,248
	736,030	655,814
Preferred Stock (Note 2):		
Not subject to mandatory redemption	140,008	140,008
Subject to mandatory redemption at par	89,400	89,400
	229,408	229,408
Long-term Debt (Note 3)	865,659	839,749
	1,831,097	1,724,971
Current Liabilities:		
Notes payable (Note 4)	61,130	9,110
Long-term debt due within one year	2,737	17,226
Accounts payable	173,878	162,309
Dividends payable	23,027	20,164
Customers' deposits	7,057	12,837
Accrued taxes	48,972	39,426
Accrued interest	17,233	17,798
Other	27,614	23,629
Total Current Liabilities	361,648	302,499
Deferred Credits:		
Customers' advances for construction	25,279	24,958
Investment credit (being amortized over the productive lives of the related property)	127,910	105,763
Accumulated deferred income taxes (Notes 1 and 8)	63,769	42,454
Other	21,265	15,725
	238,223	188,900
Commitments and Contingencies (Note 6)		
Total Capital and Liabilities	$2,430,968	$2,216,370

Consolidated Statement of Income

Years ended December 31, 1981, 1980 and 1979
Public Service Company of Colorado and Subsidiaries

	1981	1980	1979
	(Thousands of Dollars)		
Operating Revenues:			
Electric	$ 742,104	$ 640,749	$ 507,587
Gas	582,434	502,919	410,537
Other	11,633	11,976	8,386
	1,336,171	1,155,644	926,510
Operating Expenses:			
Fuel used in generation	171,657	184,073	176,413
Gas purchased for resale	462,291	388,852	310,129
Purchased power	113,235	91,414	29,425
Other operating expenses	192,639	168,114	162,858
Maintenance	49,735	46,646	37,092
Depreciation (Note 1)	73,643	61,594	55,390
Taxes (other than income taxes) (Note 9)	64,001	40,433	38,033
Income taxes (Note 8)	67,914	52,190	26,826
	1,195,115	1,033,316	836,766
Operating Income	141,056	122,328	89,744
Other Income and Deductions:			
Allowance for equity funds used during construction (Note 1)	17,648	14,947	10,893
Miscellaneous income and deductions—net	5,816	6,885	2,269
	164,520	144,160	102,906
Interest Charges:			
Interest on long-term debt	66,481	65,108	50,717
Amortization of debt discount and expense less premium (Note 1)	650	528	239
Other interest	7,667	7,757	4,123
Allowance for borrowed funds used during construction (Note 1)	(11,033)	(14,260)	(7,982)
	63,765	59,133	47,097
Net Income	100,755	85,027	55,809
Dividend Requirements on Preferred Stock	16,661	15,020	13,536
Earnings Available for Common Stock	$ 84,094	$ 70,007	$ 42,273
Shares of Common Stock Outstanding (thousands):			
Year-end	44,896	39,990	32,326
Average	42,728	36,412	31,225
Earnings Per Average Share of Common Stock Outstanding	$1.97	$1.92	$1.35
Dividends Per Share of Common Stock:			
Paid	$1.66	$1.60	$1.60
Declared	$1.68	$1.60	$1.60

See accompanying notes.

Consolidated Statement of Retained Earnings

Years ended December 31, 1981, 1980 and 1979
Public Service Company of Colorado and Subsidiaries

	1981	1980	1979
	(Thousands of Dollars)		
Retained Earnings at Beginning of Year	$141,248	$136,314	$145,853
Net Income	100,755	85,027	55,809
	242,003	221,341	201,662
Dividends:			
On cumulative preferred stock:			
$100 par value:			
4.20% series	420	420	420
4 1/4 % series	744	744	744
4 1/2 % series	293	293	293
4.64% series	742	742	742
4.90% series	735	735	735
4.90% 2nd series	735	735	735
7.15% series	1,787	1,787	1,787
7.50% series	2,250	2,250	2,250
8.40% series	2,890	2,890	2,890
12.50% series	3,125	2,005	—
$25 par value:			
8.40% series	2,940	2,940	2,940
	16,661	15,541	13,536
On common stock:			
$1.68 per share in 1981, $1.60 per share in 1980 and 1979	72,984	60,217	50,421
	89,645	75,758	63,957
Expense of Issuing Stock	2,192	4,335	1,391
	91,837	80,093	65,348
Retained Earnings at End of Year	$150,166	$141,248	$136,314

See accompanying notes.

Consolidated Statement of Source of Funds For Plant Construction Expenditures

Years ended December 31, 1981, 1980 and 1979
Public Service Company of Colorado and Subsidiaries

	1981	1980	1979
	(Thousands of Dollars)		
Source of Funds:			
Funds from Operations:			
Net Income	$100,755	$ 85,027	$ 55,809
Non-cash Charges (Credits) Against Income			
Not Involving Working Capital in the Current Period:			
Depreciation charged to operating expenses	73,643	61,594	55,990
Depreciation charged to clearing and other accounts	6,000	6,324	5,105
Allowance for funds used during construction	(28,680)	(29,207)	(18,875)
Investment credit — net of amortization	22,147	24,772	20,213
Deferred income taxes	22,579	13,387	2,018
Funds from Operations	196,444	161,897	120,260
Dividends:			
On preferred stock	(16,661)	(15,541)	(13,536)
On common stock	(72,984)	(60,217)	(50,421)
Funds Retained in the Business	106,799	86,139	56,303
Funds from Financing — Net Proceeds:			
Proceeds from sale of common stock	69,154	91,262	48,012
Proceeds from sale of preferred stock	—	24,861	—
Proceeds from sale of first mortgage bonds	49,531	49,448	—
Proceeds froms sale of pollution control bonds and notes	28,489	37,073	40,380
Proceeds from issue of long-term notes	1,633	2,807	16,353
Funds from Financing	148,807	205,451	104,745
Funds from Settlement Agreement (Note 11)	7,993	2,357	60,000
Reduction in Long-term Debt	(54,611)	(17,200)	(2,246)
Other Sources — Net	686	6,340	18,327
Total Funds Available	209,674	283,087	237,129
Increase (Decrease) in Working Capital	(18,393)	49,690	(64,802)
Net Plant Construction Expenditures	228,067	233,397	301,931
Allowance for Funds Used During Construction	28,680	29,207	18,875
Gross Plant Construction Expenditures	$256,747	$262,604	$320,806
Increase (Decrease) in Components of Working Capital:			
Current Assets:			
Cash	$ 11,384	$ 6,791	$ (13,190)
Temporary cash investments	551	(8,972)	9,918
Accounts and notes receivable	6,691	(3,554)	33,919
Fuel inventory	5,025	20,469	6,918
Materials and supplies	6,474	(5,666)	16,014
Other	10,631	9,125	9,167
	40,756	18,193	62,746
Current Liabilities:			
Notes payable	52,020	(53,076)	40,004
Long-term debt due within one year	(14,489)	14,976	18
Accounts payable	11,569	[illegible]	63,641
Accrued liabilities	8,981	[illegible]	7,048
Customers' refund	—	(10,817)	10,817
Other	1,068	(832)	6,020
	59,149	(31,497)	127,548
Increase (Decrease) in Working Capital	$(18,393)	$ 49,690	$ (64,802)

See accompanying notes.

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Consolidation:
The Company follows the practice of consolidating the accounts of its significant subsidiaries.

Depreciation policy:
The Company and its subsidiaries, except Fuel Resources Development Co. (Fuelco), use straight-line depreciation for accounting purposes. Composite rates are used for the various classes of depreciable assets.

Depreciation rates include provisions for disposal and removal costs of property, plant and equipment, including the nuclear plant. Total depreciation expense approximates an annual rate of 3.45% on the average cost of depreciable properties. Fuelco uses the unit-of-production depreciation method for accounting purposes. For income tax purposes, the Company and its subsidiaries use accelerated depreciation and other elections provided by the tax laws.

Pursuant to an order of the Public Utilities Commission of the State of Colorado (CPUC), the composite depreciation rates include a provision for the estimated cost of decommissioning the nuclear plant after its service life. Funds equal to the provision for decommissioning costs are transferred to an independent trustee and can be used only for the decommissioning of the nuclear plant.

Replacements and betterments representing units of property are capitalized. Items that represent less than units of property are charged to operations as maintenance. The cost of units of property retired, together with cost of removal, less salvage, is charged in full against the accumulated provision for depreciation.

Amortization of nuclear fuel:
Under the Settlement Agreement with General Atomic Company, the prime contractor for the Fort St. Vrain Nuclear Generating Station, the Company received ownership of the reactor core and all fuel elements at the Fort St. Vrain Nuclear Generating Station as of January 1, 1979, and the General Atomic Company agreed to make available to the Company, at no charge (except certain possible incremental costs), nuclear fuel elements sufficient to operate the plant at 200 Mw at 60% capacity through December 31, 1984, or until 16,166,400 Mwh thermal are produced, or could have been produced, whichever is earlier. The nuclear fuel has been assigned a fair value and recorded on the balance sheet as property, plant and equipment, with a corresponding credit to miscellaneous deferred income. For income tax purposes, the nuclear fuel and spare parts have been treated as income. The assigned cost of nuclear fuel is amortized to fuel expense based on the quantity of heat produced for the generation of electric energy with a like amount credited to miscellaneous income. The Company's policy is to include in the cost of nuclear fuel a provision for spent fuel disposal costs. The Company expects that the reimbursement from the supplier of the nuclear fuel (see Note 11) is adequate to provide for the disposal costs of the fuel presently in use.

Deferred income taxes:
In an order dated November 1, 1977, the CPUC allowed as an operating expense a provision for certain deferred income taxes resulting from the use of accelerated depreciation on property additions made on or after December 1, 1975. Effective December 1, 1977, the Company began providing for these deferred income taxes. The CPUC, in an order dated December 1, 1981, with respect to the Company's application for a rate increase, authorized the Company to take advantage of the Accelerated Cost Recovery System (ACRS) normalization provided by the Economic Recovery Tax Act of 1981 (ERTA) for property acquired after December 31, 1980. Deferred taxes are not provided on other book-tax differences, except for differences in amortization relating to certain pollution control facilities, the nuclear fuel and spare parts.

In an order dated November 14, 1978, the CPUC allowed Western Slope Gas Company to include as an operating expense the provision for deferred income taxes resulting from the use of accelerated depreciation on property additions made on or after April 1, 1977. Deferred taxes are not provided on other book-tax differences.

In accordance with an order dated June 13, 1969, from the Public Service Commission of Wyoming, Cheyenne Light, Fuel and Power Company provides for deferred federal income taxes on the difference between depreciation as computed for accounting purposes and tax purposes.

In accordance with an order from the CPUC, Home Light and Power Company provides for deferred income taxes on the difference between depreciation as computed for accounting purposes and tax purposes.

In accordance with the requirements of the Financial Accounting Standards Board, Fuelco provides for deferred income taxes applicable to exploration and development costs. Fuelco also provides for deferred income taxes on certain other book-tax differences.

Notes to Consolidated Financial Statements
(continued)

Investment credit:
The investment credit provided by ERTA and investment credits provided by previous tax laws are being deferred and amortized to income over the productive lives of the related property.

The Employee Stock Ownership Plan was established, effective January 1, 1976, to enable the Company to claim under the Tax Reduction Act of 1975 and the Tax Reform Act of 1976 an additional one percent investment credit on its consolidated federal tax return for contributions to a trustee for eligible employees. Contributions are made in cash or the Company's Common Stock and, if cash, are invested in the Company's Common Stock. The Plan also enables the Company to claim an additional one-half percent investment credit to the extent of employee contributions which are to be matched by the Company. The Plan also permits limited additional contributions by employees.

Amortization of debt premium, discount and expense:
Debt premium, discount and expense is being amortized by charges to income over the respective original lives of the applicable issues.

Allowance for funds used during construction (AFDC):
AFDC, which does not represent current cash earnings, is defined in the system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and the CPUC as the net cost during the period of construction of borrowed funds used for construction purposes, and a reasonable rate on funds derived from other sources. In accordance with such system of accounts, the Company capitalizes AFDC as a part of the cost of utility plant, with a credit to nonoperating income for the portion of AFDC attributable to equity funds and a reduction of interest charges for the portion of AFDC attributable to borrowed funds. The capitalization of AFDC results in the inclusion of AFDC in rate base and the recovery thereof through future billings to customers. In its November 1977 order, the CPUC directed that in the future, the Company is to capitalize AFDC at its authorized rate of return, but not to exceed the amount allowed by the formula prescribed by the FERC. Accordingly, the rates used by the Company in 1979 were 9.14% for the first eleven months and 9.53% for December 1979. For the first five months of 1980, the rate used was 9.53% and for the last seven months the rate used was 9.57%. For 1981, the rates used were 10.19% for the first eleven months and 10.75% for December. These rates represented the Company's authorized rates of return at that time and did not exceed the amount allowed by the formula prescribed by the FERC.

Revenues:
The Company reads customers' meters on a cycle basis, and renders bills each month. Revenues are recorded when the customers are billed.

2. Capital Stock

	1981		1980	
	Shares	Amount (Thousands of Dollars)	Shares	Amount (Thousands of Dollars)
Cumulative preferred stock, $100 par value:				
Authorized	3,000,000		3,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
4.20% series	100,000	$ 10,000	100,000	$ 10,000
4-¼% series (includes $7,500 premium)	175,000	17,508	175,000	17,508
4-½% series	65,000	6,500	65,000	6,500
4.64% series	160,000	16,000	160,000	16,000
4.90% series	150,000	15,000	150,000	15,000
4.90% 2nd series	150,000	15,000	150,000	15,000
7.15% series	250,000	25,000	250,000	25,000
Total	1,050,000	$105,008	1,050,000	$105,008
Subject to mandatory redemption:				
7.50% series	300,000	$ 30,000	300,000	$ 30,000
8.40% series	344,000	34,400	344,000	34,400
12.50% series	250,000	25,000	250,000	25,000
Total	894,000	$ 89,400	894,000	$ 89,400

Capital Stock (continued)

	1981 Shares	1981 Amount (Thousands of Dollars)	1980 Shares	1980 Amount (Thousands of Dollars)
Cumulative preferred stock ($25), $25 par value:				
Authorized	4,000,000		4,000,000	
Issued and outstanding:				
Not subject to mandatory redemption				
8.40% series	1,400,000	$ 35,000	1,400,000	$ 35,000
Common stock, $5 par value:				
Authorized	80,000,000		80,000,000	
Issued and outstanding	44,895,939	$224,480	39,989,753	$199,949
Premium on common stock		361,344		314,442
Installments received from employees on subscriptions aggregating $122,925 for 8,195 shares at December 31, 1981, and $416,259 for 34,441 shares at December 31, 1980		40		175
Total		$585,864		$514,566

Changes in common stock and premium on common stock for 1981, 1980, and 1979 are as follows:

	Price range per share	Common stock (Thousands of Dollars)	Premium on common stock (Thousands of Dollars)
Balance, January 1, 1979		$146,252	$223,444
322,627 shares sold under Dividend Reinvestment Plan	$13.44 to 16.81	1,613	3,326
219,981 shares sold under Employee Stock Ownership Plan	$13.31 to 16.71	1,100	2,401
1,177 shares sold to employees	$18.13	6	15
2,532,289 shares sold to the public and employees	$16.13	12,661	28,172
Balance, December 31, 1979		161,632	257,358
781,497 shares sold under Dividend Reinvestment Plan	$11.04 to 14.75	3,907	5,711
46,726 shares sold under Employee Stock Ownership Plan	$12.44 to 14.19	234	366
11,080 shares sold to employees	$16.13	55	123
2,806,534 shares sold to the public and employees	$11.50	14,033	18,242
4,017,498 shares sold to the public and employees	$13.13	20,088	32,642
Balance, December 31, 1980		199,949	314,442
895,405 shares sold under Dividend Reinvestment Plan	$12.94 to 14.69	4,477	7,530
475,073 shares sold under Employee Stock Ownership Plan	$13.50 to 14.56	2,375	4,114
21,960 shares sold to employees	$11.50	110	143
12,041 shares sold to employees	$13.13	60	98
3,501,707 shares sold to the public and employees	$15.00	17,503	35,017
Balance, December 31, 1981		$224,480	$361,344

Notes to Consolidated Financial Statements
(continued)

On July 10, 1980, the Company received $25,000,000 from the sale of 250,000 shares of 12.50% cumulative preferred stock, $100 par value. The shares were placed in a private transaction with a group of institutional investors. No other changes in preferred stock occurred in the three years ended December 31, 1981.

The preferred stock may be redeemed at the option of the Company upon at least 30, but not more than 60 days' notice, in accordance with the following schedule of prices plus an amount equal to the accrued dividends to the date fixed for redemption:

$100 par value:
Not subject to mandatory redemption:
4.20% series: $101; 4-¼% series: $101; 4-½% series: $101; 4.64% series: $101; 4.90% series: $101; 4.90% 2nd series: $101; 7.15% series: $105 prior to March 1, 1982, $102.50 thereafter but prior to March 1, 1987, and $101 on and after that date.

Subject to mandatory redemption:
7.50% series: $112 on or prior to August 31, 1983, $105 on or prior to August 31, 1984, and reducing each year thereafter by $.25 per share until August 31, 2003, after which the redemption price is $100; 8.40% series: $112 on or prior to July 31, 1984, $105 on or prior to July 31, 1985, and reducing each year thereafter by $.25 per share until July 31, 2004, after which the redemption price is $100; 12.50% series: $106.25 on or prior to June 30, 1984 (not callable prior to July 1, 1983), $105.21 on or prior to June 30, 1985, $104.17 on or prior to June 30, 1986, $103.13 on or prior to June 30, 1987, $102.09 on or prior to June 30, 1988, and $101.05 on or prior to June 30, 1989, after which the redemption price is $100.

Starting in 1984 and in each year thereafter, the Company will offer to repurchase up to 12,000 shares of the 7.50% series at $100 per share, plus accrued dividends to the date set for repurchase; starting in 1985 and in each year thereafter, the Company will offer to repurchase up to 13,760 shares of the 8.40% series at $100 per share, plus accrued dividends to the date set for repurchase; starting in 1986 and in each year thereafter, the Company will set aside in a sinking fund an amount sufficient for the redemption of 50,000 shares of the 12.50% series at $100 per share, plus accrued dividends to the date set for repurchase. The Company shall be entitled, at its option, on any one of the sinking fund redemption dates, to redeem up to 50,000 shares of the 12.50% series, in addition to the shares otherwise required to be redeemed on such sinking fund redemption date, at $100 per share plus an amount equal to the accrued and unpaid dividends thereon to such sinking fund redemption date, provided, however, that the option of the Company to so redeem up to 50,000 additional shares of the 12.50% series may be exercised only once.

$25 par value:
Not subject to mandatory redemption:
8.40% series: $26.50 prior to December 1, 1986, $25.75 thereafter but prior to December 1, 1991, and $25.25 on or after that date.

3. Long-term Debt

	1981	1980
	(Thousands of Dollars)	
Public Service Company of Colorado:		
First mortgage bonds:		
3-1/8% series, due October 1, 1984	$ 20,000	$ 20,000
15% series, due March 1, 1987	50,000	50,000
4-3/8% series, due May 1, 1987	30,000	30,000
4-5/8% series, due May 1, 1989	20,000	20,000
4-1/2% series, due October 1, 1991	30,000	30,000
4-5/8% series, due March 1, 1992	8,800	8,800
4-1/2% series, due June 1, 1994	35,000	35,000
5-3/8% series, due May 1, 1996	35,000	35,000
5-7/8% series, due July 1, 1997	35,000	35,000
6-3/4% series, due July 1, 1998	25,000	25,000
8-3/4% series, due September 1, 2000	35,000	35,000
7-1/4% series, due February 1, 2001	40,000	40,000
7-1/2% series, due August 1, 2002	50,000	50,000
7-5/8% series, due June 1, 2003	50,000	50,000
9-3/8% series, due October 1, 2005	49,500	49,500
8-1/4% series, due November 1, 2007	50,000	50,000
9-1/4% series, due October 1, 2008	50,000	50,000
16-1/4% series, due December 1, 2011	50,000	—
Pollution Control Series A, 5-7/8%, due March 1, 2004	24,000	24,000
Pollution Control Series B:		
6-5/8%, due December 1, 1985	10,500	10,500
7-1/8%, due December 1, 1990	2,000	2,000
7-5/8%, due December 1, 1995	2,500	2,500
8%, due December 1, 2004	35,000	35,000
Pollution Control Series C:		
7-1/4%, due October 1, 2004	15,000	15,000
7-3/8%, due October 1, 2005	1,960	1,960
7-3/8%, due October 1, 2006	2,105	2,105
7-3/8%, due October 1, 2007	2,260	2,260
7-3/8%, due October 1, 2008	2,425	2,425
7-3/8%, due October 1, 2009	26,250	26,250
Pollution Control Series D:		
13-3/4%, due November 1, 2011	27,380	
Less amounts held in construction fund	(425)	—
Unamortized premium	1,368	1,469
Unamortized discount	(980)	(631)
Unsecured Pollution Control Revenue Notes,		
9-1/2%, due March 1, 1982	—	37,000
Less amounts held in construction fund	—	(11,416)
	814,643	763,722
Cheyenne Light, Fuel and Power Company:		
First mortgage bonds:		
3-3/4% series, due May 1, 1985	892	915
5-1/2% series, due April 1, 1990	1,327	1,353
7-7/8% series, due April 1, 2003	4,000	4,000

Notes to Consolidated Financial Statements

(continued)

Long-term Debt (continued)	1981	1980
	(Thousands of Dollars)	
Western Slope Gas Company:		
Unsecured promissory notes:		
10%, due September 25, 1986	4	5
7-3/4%, due December 1, 1997	20,000	20,000
10.35%, due December 1, 1999	10,000	10,000
1480 Welton, Inc.:		
4-3/4% secured notes, payable in equal quarterly installments of $168,388 to June 1, 1992 covering principal and interest	5,126	5,543
6%-12% mortgage notes payable, due in installments through 1987	130	73
Secured promissory note, due in annual installments to January 9, 1984 Interest rate at prime rate less 2% (18-½% in 1981)	144	—
Fuel Resources Development Company:		
Unsecured note payable (effective interest rate 7-1/4%), due in annual principal installments of $1,066,016 through 1983	1,066	2,132
7-1/2% unsecured note payable	—	500
Unsecured notes payable (22.15% at December 31, 1980)	—	23,900
Home Light and Power Company:		
First mortgage bonds:		
3-3/4% series, due August 1, 1982	—	313
4% series, due February 1, 1986	375	384
5-1/2% series, due September 1, 1989	335	343
6% series, due April 1, 1997	711	726
7-7/8% series, due December 1, 2002	2,163	2,200
10-3/8% series, due January 1, 2003	3,580	3,640
Bannock Center Corporation:		
5-1/8%-14% mortgage notes payable, due in installments through 1996	1,163	—
	$865,659	$839,749

The 4-¾% notes of 1480 Welton, Inc. are secured by a mortgage on land in downtown Denver and an assignment of the lease between 1480 Welton, Inc. and the Company under which the latter is the lessee of the office building located thereon.

The aggregate annual maturities and sinking fund requirements during the five years subsequent to December 31, 1981 are: $6,138,000 (1982), $6,138,000 (1983), $25,938,000 (1984), $16,438,000 (1985), and $5,938,000 (1986) for the Company; and $2,791,000 (1982), $1,971,000 (1983), $985,000 (1984), $2,381,000 (1985), and $1,893,000 (1986) for its subsidiaries. The Company has been satisfying its sinking fund obligations through the application of property additions, and Cheyenne Light, Fuel and Power Company has been satisfying $60,000 annually through the application of property additions.

4. Notes Payable

Information regarding notes payable for the years ended December 31, 1981 and 1980 is as follows:

	1981	1980
	(Thousands of Dollars)	
Notes payable to banks (weighted average interest rate 13.29% at December 31, 1981 and 21.50% at December 31, 1980)	$ 27,075	$ 6,630
Commercial paper (weighted average interest rate 13.24% at December 31, 1981 and 20.63% at December 31, 1980)	34,055	2,480
	$ 61,130	$ 9,110
Maximum amount outstanding at any month-end during the period	$106,075	$126,078
Weighted average amount (based on the daily outstanding balance) outstanding for the period (weighted average interest rate 16.24% for the year ended December 31, 1981 and 13.64% for the year ended December 31, 1980)	$ 34,452	$ 44,566

5. Bank Lines of Credit, Compensating Bank Balances, and Bankers' Acceptance Facilities

Arrangements for bank lines of credit totaled $117,597,000 at December 31, 1981 and $124,447,000 at December 31, 1980. These lines of credit consisted of $23,297,000 at December 31, 1981 and $21,647,000 at December 31, 1980, maintained by compensating balances and $94,300,000 at December 31, 1981 and $102,800,000 at December 31, 1980, maintained by fee payments in lieu of balances. The compensating bank balance arrangements provide that the Company maintain average compensating balances in the amount of $2,329,700 for the period ending December 31, 1981, and $2,164,000 for the period ending December 31, 1980, and do not legally restrict the right of the Company to withdraw these compensating cash balances. These bank lines of credit are also used to support the Company's issuance of commercial paper. Arrangements for bankers' acceptance facilities amounting to $10,000,000 were available at December 31, 1981, and $15,000,000 at December 31, 1980. These arrangements are not supported by either fees or compensating balances.

6. Commitments and Contingencies

Commitments made by the Company for the purchase of various items of plant and equipment aggregated approximately $149,000,000 at December 31, 1981, and $123,000,000 at December 31, 1980.

The aggregate estimated annual commitments as of December 31, 1981 under long-term leases are as follows:

Year	Commitments
	(Thousands of Dollars)
1982	$1,693
1983	1,518
1984	1,411
1985	1,242
1986	1,218
1987-1991	5,502
1992-1996	3,479
1997-2001	683

The Company has entered into various leases for transportation equipment and miscellaneous office equipment which would be classified as capital leases as defined by the Securities and Exchange Commission and the Financial Accounting Standards Board in Statement No. 13, "*Accounting for Leases*." The Company has been advised by

Notes to Consolidated Financial Statements
(continued)

the CPUC that it has not adopted Financial Accounting Statement No. 13 and it has instructed the Company to continue to adhere to the existing Uniform System of Accounts. Had these leases been capitalized, the balance sheet at December 31, 1981 and 1980 would include in property, plant and equipment $11,074,000 and $10,694,000, respectively, representing capitalized leases with an accumulated amortization of $1,351,000 at December 31, 1981 and $549,000 at December 31, 1980. Long-term debt would include noncurrent obligations under capital leases of $9,153,000 at December 31, 1981 and $9,563,000 at December 31, 1980, and current liabilities would include current obligations under capital leases of $770,000 and $672,000, respectively. The charges to the income statement representing total lease payments recorded as rent expense were less by $87,000 at December 31, 1981, and $57,000 at December 31, 1980, and exceeded by $77,000 at December 31, 1979, the amount that would have been charged as amortization and interest expense had these leases been capitalized.

The Internal Revenue Service has under examination the Federal income tax returns of the Company and certain of its subsidiaries for 1973 through 1979. The examiners propose to include in income Fort St. Vrain Nuclear Generating Station contract refunds applied to plant costs and part of the 1979 contract settlement. The Company is resisting these proposals and believes that the final outcome of these matters will not have a material effect on the reported financial position or results of operations of the Company.

7: Retirement Plan

Total provision for pension expense under the Company's noncontributory defined benefit retirement plan covering all eligible employees was $13,708,000 in 1981, $11,263,000 in 1980, and $11,762,000 in 1979. The Company's policy is to fund pension cost accrued. A comparison of accumulated plan benefits and plan net assets as of the end of the plan's fiscal years, June 30, 1981 and 1980, is presented below:

Actuarial present value of accumulated plan benefits:	1981	1980
	(Thousands of Dollars)	
Vested	$ 85,000	$ 75,000
Nonvested	8,000	7,000
Total	$ 93,000	$ 82,000
Market value of net assets available for benefits	$140,625	$119,980

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 9½%. The actuarial present value of accumulated plan benefits is generally based on employees' history of pay and service and other appropriate factors as of the benefit valuation date and does not include anticipated future increases in employee compensation. Evaluations of accumulated plan benefits as of December 31, 1981 and 1980, were not made. However, the market values of the net assets available for benefits at these dates were approximately $144,057,000 and $122,049,000, respectively.

Effective December 1, 1978, the Company's Board of Directors began authorizing supplemental payments to retired employees and surviving beneficiaries for employees who retired prior to January 1, 1977. These payments were approximately $472,000 in 1981, $506,000 in 1980, and $529,000 in 1979. They do not constitute an employee pension benefit plan and are subject to approval annually. Payments are made from the general assets of the Company.

8. Income Tax Expense

Total income tax expense was less than the amount computed by applying the federal statutory rate to pre-tax accounting income. The reasons for this difference are as follows:

	1981	1980	1979
	(Thousands of Dollars)		
Tax computed at statutory rate on pre-tax accounting income	$77,702	$63,119	$38,012
Increase (decrease) in tax from:			
Difference between tax and book depreciation	4,255	2,368	736
Allowance for funds used during construction	(13,167)	(13,413)	(8,682)
Amortization of investment credit	(4,399)	(3,548)	(2,714)
State income taxes, net of federal income tax benefit	2,399	2,166	1,209
Other — net	1,124	1,498	(1,735)
Total income tax expense	$67,914	$52,190	$26,826
Income tax expense consists of the following:			
Current income taxes:			
Federal	$22,149	$13,080	$ 2,412
State	1,039	951	2,183
	23,188	14,031	4,595
Deferred income taxes:			
Nuclear fuel and spare parts	1,264	1,752	(5,042)
Accelerated amortization	439	(474)	237
Accelerated depreciation	18,217	10,011	7,576
Intangible drilling costs	1,466	1,227	3,221
Gain on installment sale	—	—	(11)
Lease and well impairments — net	1,168	850	(3,963)
Capitalized interest	25	21	—
	22,579	13,387	2,018
Charge equivalent to reduction in income taxes due to deferred investment tax credit, net of amortization	22,147	24,772	20,213
Total income tax expense	$67,914	$52,190	$26,826

The Company has state investment tax credit carryovers of $6,103,000, expiring in 1987 and 1988, available to offset future state income taxes.

Notes to Consolidated Financial Statements

(continued)

9. Taxes (Other Than Income Taxes)

	1981	1980	1979
	(Thousands of Dollars)		
Real estate and personal property taxes	$33,667	$27,850	$25,643
Franchise taxes	16,664	1,443	1,204
Social security taxes	9,969	8,229	7,301
City and state use taxes	3,794	3,059	4,354
Miscellaneous taxes	2,296	1,955	1,641
	$66,390	$42,536	$40,143
Charged:			
Directly to income:			
Operating expenses	$64,001	$40,433	$38,033
Other	159	193	118
To property, plant and equipment and various clearing accounts	2,230	1,910	1,992
	$66,390	$42,536	$40,143

10. Segments of Business

Segment information for the year ended December 31, 1981 is as follows:

	Electric	Gas	Other	Total
	(Thousands of Dollars)			
Operating revenues	$ 742,104	$582,434	$11,633	$1,336,171
Operating expenses, excluding depreciation	501,238	547,071	5,249	1,053,558
Depreciation	58,157	13,753	1,733	73,643
Total operating expenses	559,395	560,824	6,982	1,127,201
Operating income*	$ 182,709	$ 21,610	$ 4,651	$ 208,970
Plant construction expenditures**	$ 191,491	$ 38,546	$26,710	$ 256,747
Identifiable assets, December 31, 1981:				
Utility plant**	$1,712,445	$308,023	$68,682	$2,089,150
Materials and supplies, excluding $192 of merchandise for resale	$ 36,738	$ 8,733	$ 644	46,115
Fuel inventory	$ 65,475	$ —	$ 229	65,704
Gas in underground storage	$ —	$ 12,728	$ —	12,728
Other corporate assets				217,271
				$2,430,968

* Before income taxes and interest expense

** Includes allocation of common utility property

Segment information for the year ended December 31, 1980 is as follows:

	Electric	Gas	Other	Total
	(Thousands of Dollars)			
Operating revenues	$ 640,749	$502,919	$11,976	$1,155,644
Operating expenses, excluding depreciation	455,211	457,452	6,869	919,532
Depreciation	47,320	12,769	1,505	61,594
Total operating expenses	502,531	470,221	8,374	981,126
Operating income*	$ 138,218	$ 32,698	$ 3,602	$ 174,518
Plant construction expenditures**	$ 221,146	$ 35,823	$ 5,635	$ 262,604
Identifiable assets, December 31, 1980:				
Utility plant**	$1,585,703	$289,631	$45,240	$1,920,574
Materials and supplies, excluding $202 of merchandise for resale	$ 32,688	$ 6,026	$ 917	39,631
Fuel inventory	$ 60,503	$ —	$ 176	60,679
Gas in underground storage	$ —	$ 8,528	$ —	8,528
Other corporate assets				186,958
				$2,216,370

* Before income taxes and interest expense

** Includes allocation of common utility property

Segment information for the year ended December 31, 1979 is as follows:

	Electric	Gas	Other	Total
	(Thousands of Dollars)			
Operating revenues	$ 507,587	$410,537	$ 8,386	$ 926,510
Operating expenses, excluding depreciation	366,330	373,726	13,894	753,950
Depreciation	42,906	11,835	1,249	55,990
Total operating expenses	409,236	385,561	15,143	809,940
Operating income (loss)*	$ 98,351	$ 24,976	$ (6,757)	$ 116,570
Plant construction expenditures**	$ 279,037	$ 35,334	$ 6,435	$ 320,806
Identifiable assets, December 31, 1979:				
Utility plant**	$1,419,396	$268,707	$44,380	$1,732,483
Materials and supplies, excluding $375 of merchandise for resale	$ 37,595	$ 7,050	$ 479	45,124
Fuel inventory	$ 39,993	$ —	$ 217	40,210
Gas in underground storage	$ —	$ 1,944	$ —	1,944
Other corporate assets				191,503
				$2,011,264

* Before income taxes and interest expense

** Includes allocation of common utility property

Notes to Consolidated Financial Statements
(continued)

11. Fort St. Vrain Settlement

On June 27, 1979, the Company and the prime contractor for th Fort St. Vrain Nuclear Generating Station, General Atomic Company (GAC), which is an equal partnership of Scallop Nuclear Inc. (a company of the Royal Dutch Shell Group) and Gulf Oil Corporation entered into a Settlement Agreement, a Services Agreement and a Fuel and Fabrication Agreement satisfying and settling all contracts and claims between the Company and GAC relative to Fort St. Vrain. The terms of these Agreements include the following: (a) GAC paid to the Company, upon execution of the Settlement Agreement, $60,000,000 as an adjustment of the plant cost for the reduction in the plant's capacity from 330 Mw at 80% capacity factor to 200 Mw at 60% capacity factor; however, GAC made no warranty as to the capacity of the plant; (b) GAC will contribute to the Company, between 1980 and 1984, $97,050,427 for the cost of replacing the 130 Mw reduction in capacity at Fort St. Vrain with future electric generating facilities and up to $8,068,791 for reimbursement for shipment, storage, handling and disposal of spent nuclear fuel for which the Company will bear the responsibility and the cost; (c) ownership of the reactor c e and all fuel elements at the plant was transferred to the Company by GAC as of January 1, 1979, and GAC will make available to the Company, at no charge (except certain possible incremental costs), nuclear fuel elements sufficient to operate the plant at 200 Mw at 60% capacity through December 31, 1984, or until 16,166,400 Mwh thermal are produced, or could have been produced, whichever is earlier; (d) through 1992, GAC will provide or arrange to provide fuel fabrication services to the Company, and the Company will reimburse GAC for GAC's cost, for the manufacture of additional fuel elements for use at Fort St. Vrain as the Company, at its own discretion, may schedule; (e) GAC transferred ownership of spare parts and equipment for the plant, effective January 1, 1979; (f) GAC will fund, up to $5,000,000, the study and resolution of certain plant performance problems; (g) GAC will fund, up to $10,000,000, work related to certain open work items, documentation and seismic studies; (h) upon execution of the Settlement Agreement but effective as of January 1, 1979 the Company received title to the Fort Lupton Gas Turbine Units; and (i) upon execution of the Settlement Agreement but effective as of January 1, 1979, the Company accepted Fort St. Vrain for commercial operation.

12. Effects of Changing Prices (Unaudited)

The following supplementary information is supplied in accordance with the requirements of Financial Accounting Standards Board ("FASB") Statement No. 33, "*Financial Reporting and Changing Prices*," in order to provide certain information about the effects of general inflation and changes in specific prices on the historical cost financial data of the Company. This supplementary information should be viewed as an estimate rather than a precise measure.

Two methods have been prescribed for measuring the effects of changing prices. The *Constant Dollar* method restates historical financial data to units of equivalent purchasing power by applying the Consumer Price Index for All Urban Consumers (CPI-U) to the original historical cost of the Company's surviving property, plant and equipment. Constant Dollar adjusted information indicates how the Company has been affected by the decline in purchasing power of the dollar (general inflation).

The *Current Cost* method adjusts historical financial data to reflect changes in the specific prices of the Company's property, plant and equipment from the date these assets were acquired to the present. This estimated cost of replacing the productive capacity of existing plant assets is primarily determined by indexing surviving property, plant and equipment (including land, land rights, property held for future use, and construction work in progress) by the Handy-Whitman Index of Public Utility Construction Costs. *Current Cost* adjusted information indicates how the Company has been affected by the increased cost of maintaining its existing productive capacity. *Current Costs* differ from *Constant Dollar* amounts to the extent that specific prices have increased more or less than prices in general.

As shown in the following statement, income from continuing operations developed under both *Constant Dollar* and *Current Cost* methods is lower than that determined under the historical cost method used for the primary financial statements. Of the revenue and expense elements from which the income figure is derived, only depreciation expense has been restated by applying the Company's depreciation rates to the indexed amounts of *Constant Dollar* and *Current Cost* adjusted property, plant and equipment. All other income statement items are considered to have been effectively transacted at average price levels for the current year, and accordingly have not been restated.

Fuel inventories, the cost of fuel used in generation, and gas purchased for resale have not been restated from their historical cost in nominal dollars. Regulation limits the recovery of fuel and purchased gas costs through the operation of adjustment clauses or adjustments in basic rate schedules to actual costs. For this reason fuel and gas inventories are effectively monetary assets.

As prescribed in FASB Statement No. 33, income taxes were not adjusted to reflect the effects of changing prices. This requirement is appropriate, since current income tax policy ignores the effects of inflation in measuring taxable income and the higher depreciation expense experienced under *Constant Dollar* and *Current Cost* accounting is not tax deductible. The Company's effective income tax rate, when taxable income has been adjusted for inflation, is 75 percent under the *Constant Dollar* method and 132 percent under the *Current Cost* method for 1981, both of which exceed the reported effective tax rate of 40 percent and the statutory rate of 49 percent.

Statement of Income from Continuing Operations Adjusted for Changing Prices
For the year ended December 31, 1981
(Thousands of Dollars)

	As Reported Historical Cost	Constant Dollar Average 1981 Dollars	Current Cost Average 1981 Dollars
Operating revenues	$1,336,171	$1,336,171	$1,336,171
Fuel used in generation expense	171,657	171,657	171,657
Gas purchased for resale expense	462,291	462,291	462,291
Depreciation expense	73,643	151,742	191,007
Other operating and maintenance expense	419,610	419,610	419,610
Income tax expense	67,914	67,914	67,914
Interest expense	63,765	63,765	63,765
Other income and deductions — net	(23,464)	(23,464)	(23,464)
	1,235,416	1,313,515	1,352,780
Income (loss) from continuing operations (excluding reduction to net recoverable amount)	$ 100,755	$ 22,656*	$ (16,609)
Increase in specific prices (current cost) of property, plant and equipment held during the year**			$ 636,636
Effect of increase in general price level			(373,328)
Reduction to net recoverable amount (Note A)		$ (103,421)	(327,464)
Excess of increase in general price level over increase in specific prices after reduction to net recoverable amount			(64,156)
Gain from decline in purchasing power of net amounts owed (Note B)		108,142	108,142
Net		$ 4,721	$ 43,986

* Including the reduction to net recoverable amount, the income (loss) from continuing operations on a constant dollar basis would have been $(80,765) for 1981.

** At December 31, 1981, current cost of property, plant and equipment, net of accumulated depreciation was $4,486,032, while historical cost (or net cost recoverable through depreciation) was $2,089,150.

Notes to Consolidated Financial Statements
(continued)

Note A. Reduction to Net Recoverable Amount

Under the CPUC and FERC rate-making provisions to which the Company is subject, only the historical cost of plant is recoverable in revenues as an amount equal to depreciation. Therefore, the portion of the cost of plant stated in terms of Constant Dollars or Current Cost which exceeds the historical cost of plant and is not presently recoverable in rates as depreciation has been reflected as the "Reduction to Net Recoverable Amount." While the rate-making process gives no recognition to the current cost of replacing property, plant and equipment, based on past practices the Company believes it will be allowed to earn on the increased cost of its net investment when replacement of facilities actually occurs.

Note B. Gain From Decline in Purchasing Power of Net Amounts Owed

This memorandum caption shows the net effect of inflationary value changes on those Company assets and liabilities carried on the balance sheet at fixed or determinable monetary settlement amounts. During a period of inflation, holders of monetary assets sustain a loss of general purchasing power while holders of monetary liabilities experience a gain. The Company's "Gain from Decline in Purchasing Power of Net Amounts Owed" is primarily attributable to the substantial amount of debt and preferred stock which has been used to finance property, plant and equipment. (In calculating this gain, preferred stock has been classified as a monetary item, which is consistent with its treatment for rate-making purposes.) Such amount does not represent funds available for distribution to shareholders.

To properly reflect the economics of rate regulation in the Statement of Income from Continuing Operations, the "Reduction to Net Recoverable Amount" should be offset by the "Gain from Decline in Purchasing Power of Net Amounts Owed."

Five-Year Comparison of Selected Financial Data Adjusted for Effects of Changing Prices

In Average 1981 Dollars (except "As reported" amounts)

	(Thousands, Except Per Share Amounts)				
	Years Ended December 31,				
	1981	1980	1979	1978	1977
Operating Revenues:					
As reported	$1,336,171	$1,155,644	$ 926,510	$ 729,778	$613,299
Adjusted to constant dollars	1,336,171	1,276,453	1,161,226	1,018,104	921,131
Income (loss) from continuing operations (excluding reduction to net recoverable amount):					
As reported	100,755	85,027	55,809		
Adjusted to constant dollars	22,656	26,057	17,122		
Adjusted to current cost	(16,609)	(18,092)	(36,604)		
Income (loss) per common share (after dividend requirements on preferred stock):					
As reported	1.97	1.92	1.35		
Adjusted to constant dollars (excluding reduction to net recoverable amount)	.14	.27	.01		
Adjusted to current cost	(.73)	(.95)	(1.71)		
Excess of increase in general price level over increase in specific prices after reduction to net recoverable amount	64,156	125,107	152,780		
Gain from decline in purchasing power of net amounts owed	108,142	147,077	163,054		
Net assets at year-end at net recoverable amount	706,236	690,250	657,439		
Cash dividends declared per common share:					
As reported	1.68	1.60	1.60	1.53	1.46
Adjusted to constant dollars	1.68	1.77	2.01	2.13	2.20
Market price per common share at year-end:					
As reported	14.25	14.25	[illegible].28	16.75	18.88
Adjusted to constant dollars	13.67	15.00	15.84	22.50	27.66
Average consumer price index*	272.6	246.8	217.5	195.4	181.5

* Base year 1967 = 100.0

13. Quarterly Financial Data (Unaudited)
Summarized quarterly data (in thousands of dollars except for per share amounts) for 1981 and 1980 are as follows:

	1981			
	Three months ended			
	March 31	June 30	September 30	December 31
Operating revenues	$387,850	$310,752	$277,582	$359,987
Operating income	$ 41,766	$ 33,109	$ 30,951	$ 35,230
Net income	$ 32,024	$ 22,100	$ 22,649	$ 23,982
Earnings available for common stock*	$ 27,859	$ 17,935	$ 18,484	$ 19,817
Average common shares outstanding (thousands)	40,138	41,569	44,406	44,799
Earnings per average common share*	$0.69	$0.43	$0.42	$0.44

	1980			
	Three months ended			
	March 31	June 30	September 30	December 31
Operating revenues	$329,252	$271,315	$233,229	$321,848
Operating income	$ 34,194	$ 25,867	$ 29,242	$ 33,025
Net income	$ 22,930	$ 15,922	$ 20,661	$ 25,514
Earnings available for common stock	$ 19,546	$ 12,538	$ 16,574	$ 21,349
Average common shares outstanding (thousands)	33,377	35,417	36,962	39,890
Earnings per average common share*	$0.59	$0.35	$0.45	$0.54

* Due to rounding, quarterly figures do not add to annual total.

Report of Certified Public Accountants
The Board of Directors and Shareholders
Public Service Company of Colorado

We have examined the accompanying consolidated balance sheet of Public Service Company of Colorado and subsidiaries at December 31, 1981 and 1980, and the related consolidated statements of income, retained earnings and source of funds for plant construction expenditures for each of the three years in the period ended December 31, 1981. Our examinations were 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.

In our opinion, the statements mentioned above present fairly the consolidated financial position of Public Service Company of Colorado and subsidiaries at December 31, 1981 and 1980, and the consolidated results of operations and source of funds for plant construction expenditures for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles applied on a consistent basis during the period.

Arthur Young & Company

Arthur Young & Company
Denver, Colorado
February 5, 1982

Board of Directors and Officers

Board of Directors

Robert T. Person, Denver, CO (1957)
Chairman of the Board, Age 67

Richard F. Walker, Denver, CO (1976)
President and Chief Executive Officer, Age 57

William T. Blackburn, Denver, CO (1965)
Resident Partner, Vaughey, Vaughey & Blackburn (Independent Oil Producers), Age 65

Doris M. Drury, PhD, Denver, CO (1975)
University of Denver
Professor of Economics and Director Public Affairs Programs, Age 53

Robert E. Kelly, Denver, CO (1978)
Vice President
Fuel Supply and Gas Operations, Age 63

George B. McKinley, Grand Junction, CO (1976)
President and Chief Executive Officer
Central Bancorporation, Inc., Age 54

John A. McKinney, Denver, CO (1979)
Chairman of the Board
and Chief Executive Officer
Manville Corporation, Age 58

C. Keith Millen, Denver, CO (1969)
Senior Vice President of Operations, Age 59

Will F. Nicholson, Jr., Denver, CO (1981)
President, Colorado National Bankshares, Inc., Age 52

Bryant O'Donnell, Denver, CO (1972)
Executive Vice President and General Counsel, Age 56

Nicholas R. Petry, Denver, CO (1961)
Chairman of the Board
Petry-Vanni Construction Company
Managing Partner of N. G. Petry Construction Company, Age 63

J. Michael Powers, Cheyenne, WY (1978)
President, Powers Builders' Supply, Age 39

King D. Shwayder, Denver, CO (1967)
Former Chairman of the Board, Samsonite Corp., subsidiary of Beatrice Foods Company, Age 71

( ) Year elected to the Board of Directors

We deeply regret the death of A. L. Feldman, Chairman and Chief Executive Officer of Continental Airlines. Mr. Feldman was a valued and respected member of the Board of Directors and we will miss his counsel. Will F. Nicholson, Jr. was named to the Board of Directors in December to replace Mr. Feldman.

Executive Committee

Robert T. Person
Richard F. Walker
William T. Blackburn
George B. McKinley
Nicholas R. Petry
King D. Shwayder

Audit Committee

Doris M. Drury
King D. Shwayder
J. Michael Powers

Executive Officers

Robert T. Person (45), Age 67
Chairman of the Board

Richard F. Walker (32), Age 57
President and Chief Executive Officer

Bryant O'Donnell (31), Age 56
Executive Vice President and General Counsel

C. Keith Millen (35), Age 59
Senior Vice President, Operations

Harvey P. Blichmann (32), Age 54
Vice President, Strategic Planning and Administrative Services

James N. Bumpus (17), Age 47
Vice President, Finance and Treasurer

Clark B. Ewald (22), Age 47
Vice President, Employee Relations

J. Kenneth Fuller (33), Age 58
Vice President, Electric Engineering and Planning

Delwin D. Hock (19), Age 46
Vice President, Accounting and Secretary

Robert E. Kelly (35), Age 63
Vice President, Fuel Supply and Gas Operations

Oscar R. Lee (31), Age 55
Vice President, Electric Production

Robert T. Person, Jr. (10), Age 39
Vice President, Public Affairs

James H. Ranniger (23), Age 45
Vice President, Rates and Regulations

Jack W. Rouse (35), Age 61
Vice President, Division Administration

( ) Denotes years of service with the Company through December, 1981

Please take a few minutes to complete and return the postage-paid, self-addressed cards below. The top card is a brief survey which will help us make our communications with you as effective as possible. The bottom card concerns our newly-instituted regional shareholder meetings and how to get additional information about the Company or your investment.

Shareholder Communications Survey

1981 Annual Report

1. About how much of PSCo's 1981 Annual Report did you read?
- ☐ all
- ☐ ¾ or more
- ☐ ½ to ¾
- ☐ ¼ to ½
- ☐ less than ¼
- ☐ none

2. Did you find the 1981 Annual Report easy to read and understand?
- ☐ very readable
- ☐ somewhat readable
- ☐ somewhat difficult
- ☐ very difficult

3. Please circle the number which represents your feelings about the quality of information, presentation, and readability of the following sections:

	Outstanding									► Poor
1981 In Retrospect	1	2	3	4	5	6	7	8	9	10
Management Commentary	1	2	3	4	5	6	7	8	9	10
A Look Ahead	1	2	3	4	5	6	7	8	9	10
Financial Profile	1	2	3	4	5	6	7	8	9	10
Operations Review	1	2	3	4	5	6	7	8	9	10
Operating and Financial Data	1	2	3	4	5	6	7	8	9	10
Shareholder Information	1	2	3	4	5	6	7	8	9	10

4. In general, please rate the overall PSCo 1981 Annual Report by circling the number below which best describes your overall impression:

Outstanding ——————► Poor

Overall, I feel the 1981 Annual Report is — 1 2 3 4 5 6 7 8 9 10

Quarterly Reports

5. About how much of PSCo's Quarterly Reports do you usually read?
- ☐ all
- ☐ more than ½
- ☐ less than ½
- ☐ none

6. How would you describe the Quarterly Reports readability?
- ☐ very readable
- ☐ somewhat readable
- ☐ somewhat difficult
- ☐ very difficult

7. In general, please rate the PSCo 1981 Quarterly Reports by circling the number below which best describes your overall impression:

Outstanding ——————► Poor

Overall, I feel the 1981 Quarterly Reports are — 1 2 3 4 5 6 7 8 9 10

Communications Programs

8. How would you describe PSCo's shareholder and investor relations programs?
- ☐ very good
- ☐ good
- ☐ adequate
- ☐ inadequate

9. Do you feel you are being adequately informed about PSCo activities?
- ☐ yes
- ☐ mostly
- ☐ not entirely
- ☐ no

10. What is your Zip Code? ______________________

Regional Shareholder Meetings

Public Service Company of Colorado is conducting a series of meetings with shareholders during 1982. Invitations to attend these meetings have been sent to shareholders who own Public Service Company stock in their name and who live within a 50-mile radius of the cities listed below.

If you wish to attend a meeting and have not already received a letter from us, please complete and return this card, indicating the meeting you wish to attend. We will send you the materials necessary for admittance.

Meetings will be held in the following areas on the indicated dates:

- ☐ Morristown, New Jersey June 9th, 9:30 a.m.
- ☐ New York City — midtown June 10th, 9:30 a.m.
- ☐ Chicago — September
- ☐ St. Louis — September
- ☐ Miami/Ft. Lauderdale — October
- ☐ Tampa/St. Petersburg — October
- ☐ Los Angeles — November
- ☐ San Francisco — November
- ☐ Seattle — November

Additional Information and Duplicate Mailings

Shareholders interested in receiving the publications or additional information listed below, or those who receive duplicate mailings of the Annual Report, are asked to check the appropriate box. Fill in account number, name and address and mail this postage-paid card.

- ☐ **Statistical Review 1971-1981**
- ☐ **Form 10-K**
- ☐ **Dividend Reinvestment Plan Information**
- ☐ **Do no want to receive more than one copy of Annual Report.**

(Please fill in account number ______________________.
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Denver, Colorado 80201

Other Officers

Dan McNellis (29), Age 53
Assistant Vice President, Governmental Affairs

Richard R. Midwinter (32), Age 56
Controller and Assistant Secretary

F. William Beier (41), Age 64
Assistant Secretary

D. V. Fetchenhier (24), Age 48
Assistant Secretary

R. C. Kelly (14), Age 35
Assistant Secretary

Leo L. Beem (34), Age 60
Assistant Treasurer

Richard L. Hunt (15), Age 39
Assistant Treasurer

Douglas S. Robertson (3), Age 39
Assistant Treasurer

( ) Denotes years of service with the Company through December, 1981

Managers, Geographic Divisions

N. Keith Coombe (29), Age 53
High Plains

Robert J. Cottle (33), Age 59
Northeast Metropolitan

Robert J. Fairchild (42), Age 60
Front Range

Ronald L. French (29), Age 54
Pueblo
Manager, Southern Region

Frank O. Hellwig (31), Age 56
Southeast Metropolitan

Douglas C. Lockhart (17), Age 39
Mountain

Robert E. Moninger (34), Age 61
Northern

M. Gordon Parker (33), Age 59
Denver Metropolitan

Lawrence F. Petrini (26), Age 51
San Luis Valley

Wallace K. Reed (35), Age 57
Boulder
Manager, Foothills Region

Harold L. Rust (26), Age 46
Platte Valley

Louis W. Supancic (30), Age 59
Southwest Metropolitan

N. James Temple, Jr. (35), Age 61
Western
Manager, Western Region

Robert J. Vidick (26), Age 54
Northwest Metropolitan

( ) Denotes years of service with the Company through December, 1981

Managers, Subsidiary Companies

Michael J. Geile (17), Age 39
Vice President and General Manager
Home Light & Power Company

John M. Hassoldt (31), Age 52
Vice President and General Manager
Western Slope Gas Company

James L. Higday (31), Age 59
President and General Manager
Cheyenne Light, Fuel and Power Company
Manager, Northern Region

Robert F. Jonas (34), Age 58
Vice President and General Manager
Fuel Resources Development Co.

( ) Denotes years of service with the Company through December, 1981

Legal Counsel
Kelly, Stansfield & O'Donnell
Denver, Colorado

Auditors
Arthur Young & Company
1670 Broadway, Suite 2500
Denver, Colorado

Transfer Agents and Registrars for All Issues of Capital Stock

Principal Transfer Agent, Registrar, Dividend Paying Agent
Morgan Guaranty Trust Company of New York
New York, New York

Co-Transfer Agents
United Bank of Denver, National Association
Denver, Colorado
Bank of America National Trust and Savings Association
San Francisco, California

Co-Registrars
United Bank of Denver, National Association
Denver, Colorado
Wells Fargo Bank, National Association
San Francisco, California

Dividend Reinvestment Plan Agent
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