Public Service

Public Service
Company of Colorado
P.O. Box 840
Denver, CO 80201-0840

16805 WCR 19 1/2; Platteville, Colorado 80651

April 5, 1994
Fort St. Vrain
Unit No. 1
P-94033

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

Docket Nos. 50-267, 72-9

SUBJECT: **Annual Financial Report**

Gentlemen:

Enclosed are ten (10) copies of the 1993 Annual Report for Public Service Company of Colorado, including the certified financial statements for 1993. This document is submitted for your information and use in accordance with 10 CFR 50.71(b), and with 10 CFR 72.80(b).

If you have any questions regarding this submittal, please contact Mr. M. H. Holmes at (303) 620-1701.

Sincerely,

Don W. Warembourg

Don W. Warembourg
Decommissioning Program Director

DWW/SWC

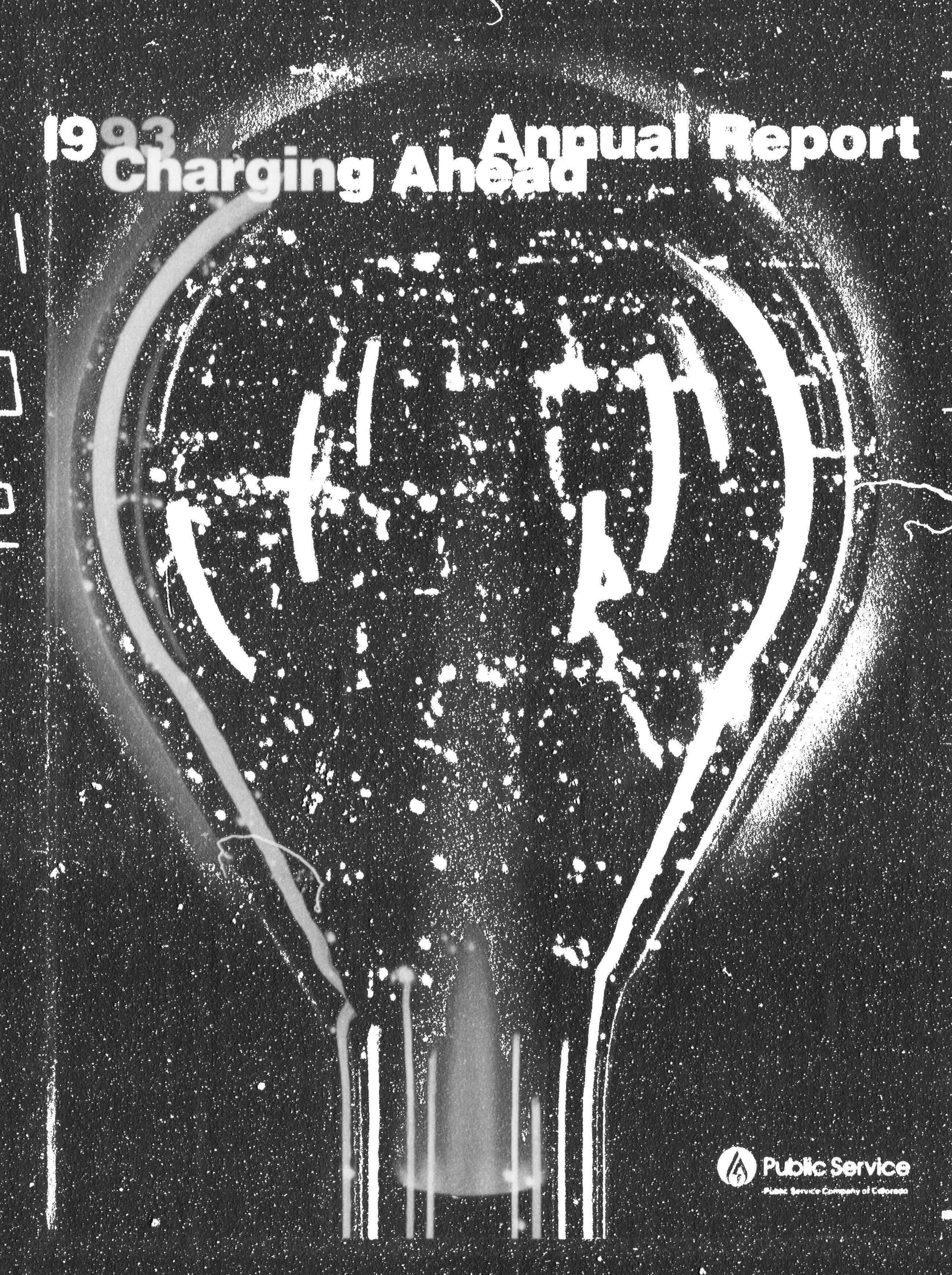
Enclosures

cc: Regional Administrator, Region IV

M004 1/10

1993 Annual Report

Charging Ahead



Public Service

Public Service Company of Colorado

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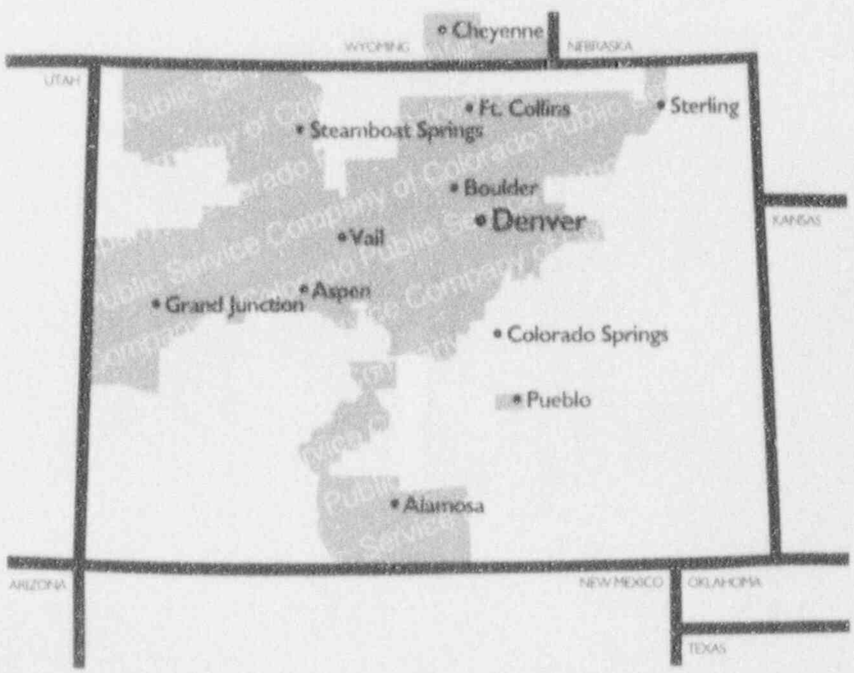
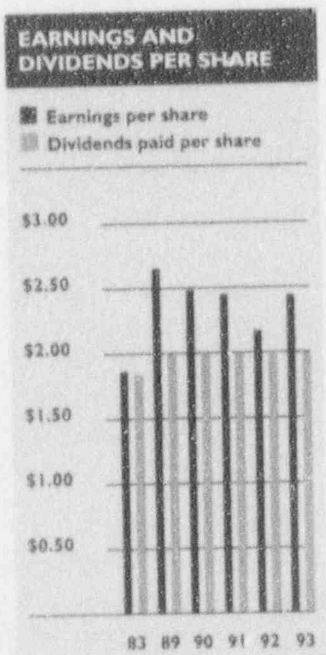
Service Territory

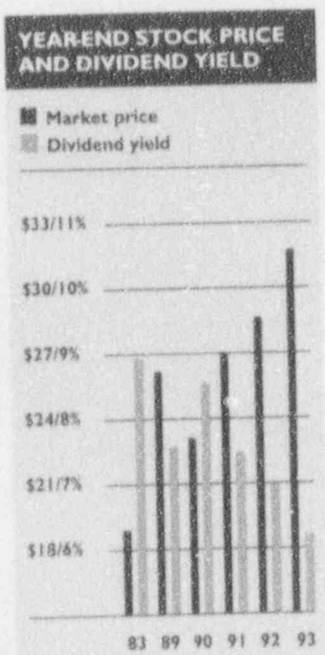


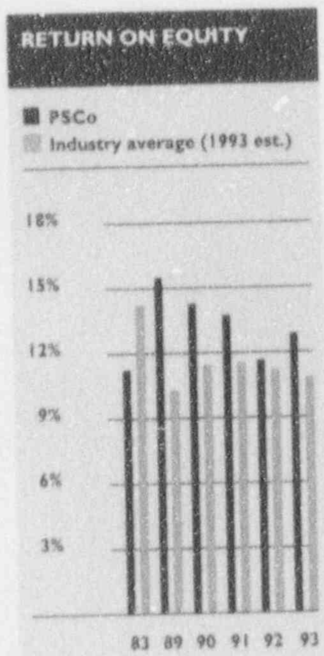
Financial & Operations Highlights

Financial	1993	1992	% Change
Earnings Per Weighted Average Share	$2.43	$2.16	12.5
Dividends Per Share	$2.00	$2.00	–
Return on Average Common Shareholder Equity	12.7%	11.7%	8.5
Common Shareholder Equity–% of Capitalization (year-end)	41.7%	40.2%	3.7
Operating Revenues (000)	$1,998,685	$1,862,273	7.3
Operating Expenses (000)	$1,717,752	$1,612,646	6.5
Net Income (000)	$ 157,360	$ 136,623	15.2
Construction Expenditures (000)	$ 293,515	$ 261,666	12.2
Colorado-Ute Asset Acquisition (000)	–	$ 265,385	–
Gross Plant Investment (000)	$5,010,063	$4,814,204	4.1
Number of Employees	6,507	6,568	(0.9)
Common Stock Shareholders	54,431	56,274	(3.3)
Common Stock Shares Outstanding (000)	60,457	58,477	3.4
Operations			
Electric Revenues (000)	$1,337,053	$1,260,769	6.1
Kilowatt-Hour Sales (millions)	23,210	21,815	6.4
Electric Customers	1,095,722*	1,015,290	7.9
Gas Revenues (000)	$ 628,324	$ 568,886	10.4
Mcf Deliveries (000)	281,396	244,956	14.9
Gas Customers	907,375*	895,338	1.3

* The criteria for counting customers was modified during 1993 with the implementation of a new Customer Information System.



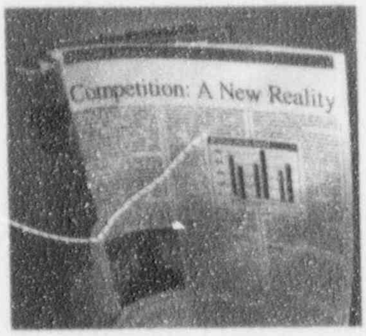




Marketplace Regulation

Heating Up

Costs Competition



Few years so clearly close one era and open another as did 1993. We made progress on our commitment to return to our core businesses by selling some of the assets of our Fuelco oil and gas exploration and production subsidiary. We also reached a milestone in decommissioning the Fort St. Vrain nuclear plant, where a major part of the plant's reactor vessel was dismantled and safely shipped away to a low-level waste disposal facility in Richland, Washington. Decommissioning continued on-schedule and on-budget. We also submitted a plan to the Colorado Public Utilities Commission to re-power the plant with natural gas.

As we put those issues in our past, new ones arose to define our future. Federal moves deregulated the supply segment of the natural gas business, and the electric business is on the verge of similarly dramatic change.

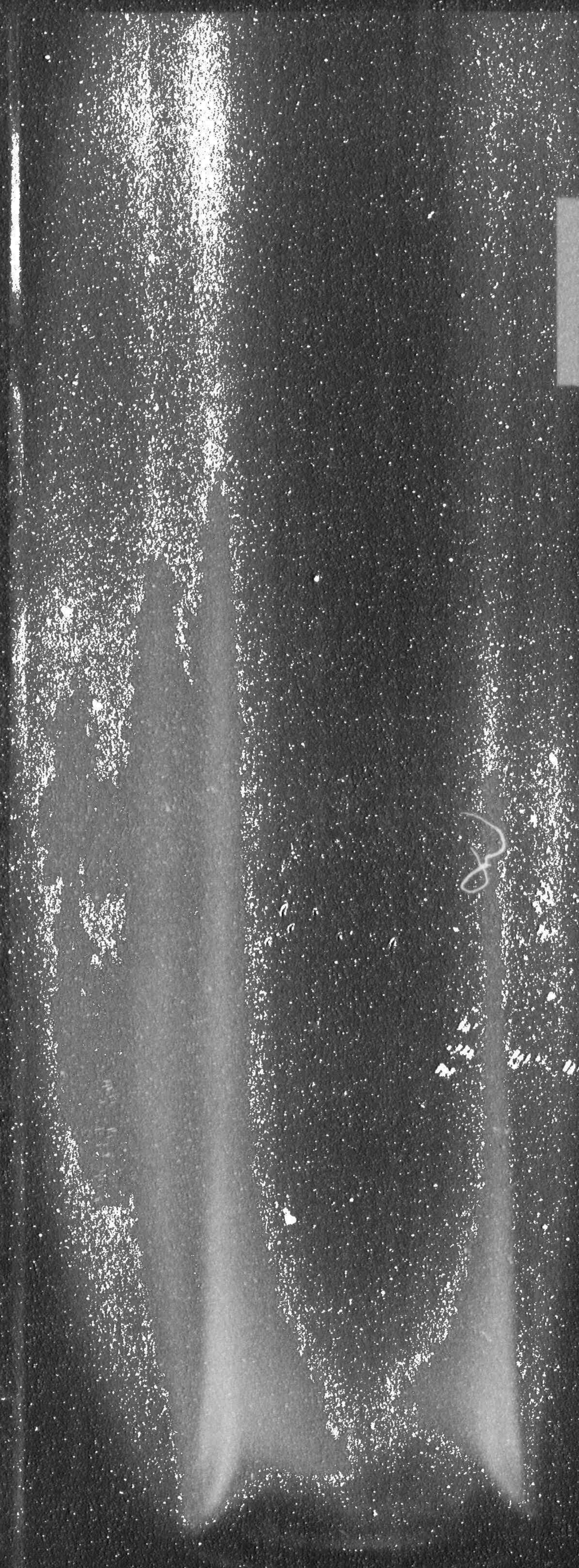
State regulatory action reduced our authorized rate of return on equity from a requested 13% to 11%. We expected the reduction in light of declining interest rates and industry trends. We were disappointed, though, that the CPUC declined to establish rates on a requested future test year, which would have brought rates more in line with actual costs. The CPUC did take a progressive step by showing a willingness to consider a current test year (instead of a historic one) in our next case.

Against this backdrop of trial and opportunity, we acted to bring costs in line with revenues. Our employees reduced 1993 operating and maintenance expenses by about 5%, some $24 million below budget. They showed that they have the will and wherewithal to continue to keep expenses in line with revenues, maintain excellent service and generate the total return shareholders expect.

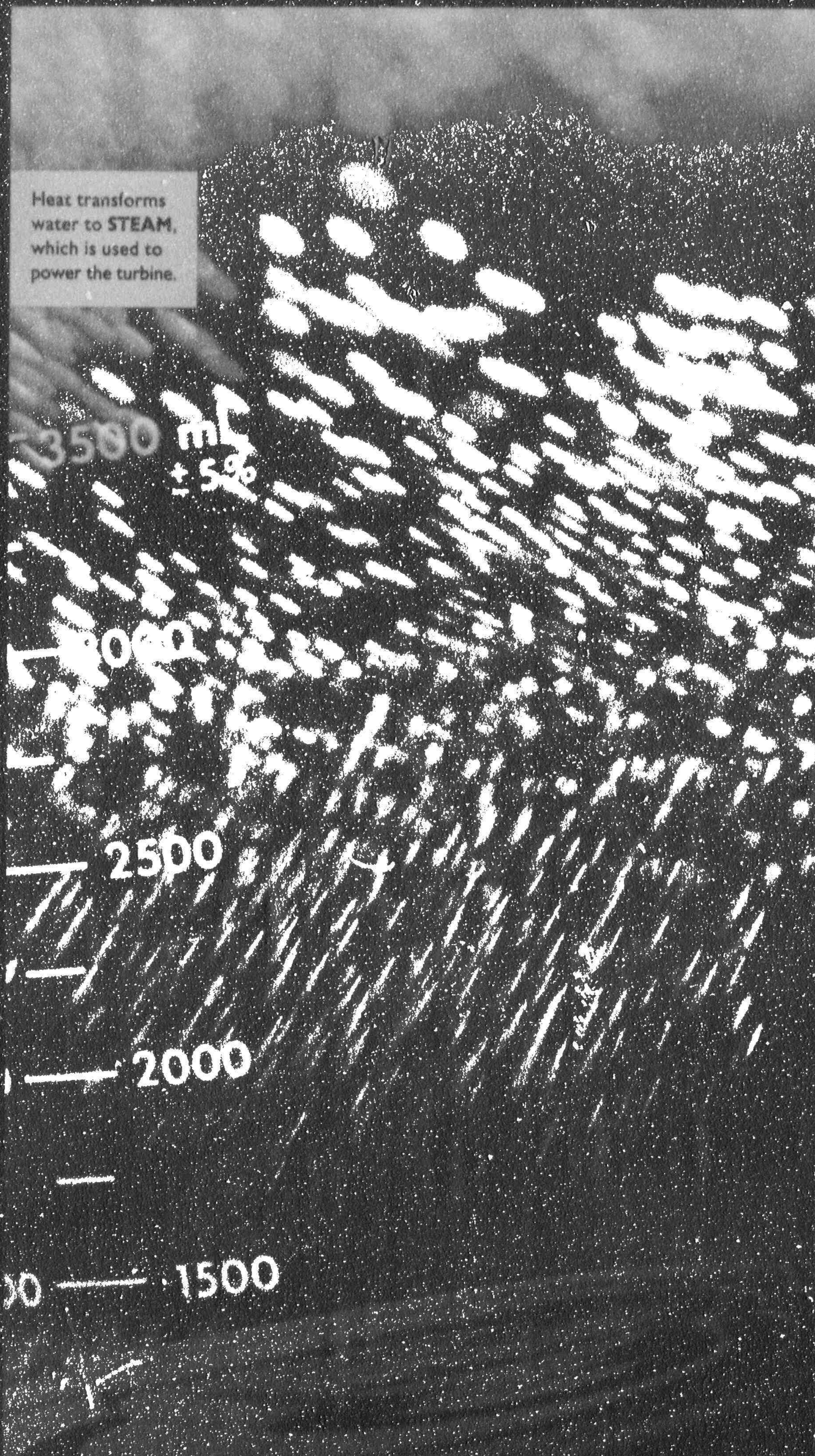
Rigorous cost control will be only one aspect of an environment characterized by accelerating change. In response to structural changes in the natural gas industry, we are continuing to concentrate our efforts on opportunities in the gas distribution business. We have created gas supply and long-term facility strategies to ensure high-quality, low-cost gas service into the next century.

Our electric business is ripe for similar dramatic change as market and technological forces portend new ways to meet the demands of an increasingly competitive marketplace. While the company has always developed an annual plan to meet our future resource needs, 1993 marked the advent of an electric Integrated Resource Plan, a formal document filed with the CPUC in October. The plan details how we will continue to meet customers' electricity needs for the next 20 years, and do so with an objective of keeping price increases less than the rate of inflation. At the same time, the plan provides for resources that slow the rate of overall system-wide plant emissions, even with growing demand for electricity.

The events of 1993 serve only to foreshadow what will change the face of our industries and our company.



In a power plant, the creation of **HEAT** is the first step to convert fossil fuels to electricity.


Heat transforms
water to STEAM,
which is used to
power the turbine.
3500 mL
± 5%
2500
2000
1500

Market Driven

Energy Solutions

Transforming Mass

Customer Partnering

Today, many of our customers have more energy supply options. To succeed in this new market environment, we are focusing on fully understanding the needs of our customers and creating energy services solutions to meet those needs.

Much of the transformation from a monopoly to a market-driven energy services provider is already occurring. In the recent past, we have exited non-core businesses such as oil and gas exploration and real estate. We merged our WestGas pipeline company into the parent company to better take advantage of the opportunities inherent in the restructuring of the natural gas industry.

The Colorado-Ute Electric Association acquisition continues to meet our expectations. Besides giving us opportunities to reduce costs through synergies between the two systems, the Ute acquisition also meant that we obtained new wholesale markets serving some of the state's fastest-growing areas, including the Vail ski area and Douglas County, south of Denver.

Our future success will be marked by how well we respond to customer needs. Knowing that acceptable results for shareholders will be achieved by meeting the needs of customers underscores the necessity for us to become a fully market-driven enterprise. For shareholders, that means taking the actions necessary to assure a continuous improvement in the total return on their investment. For employees, it means finding ways to identify and overcome barriers that impede excellent performance. For customers, it means becoming their partners to create energy solutions. This year, for example, it meant finding ways for ski areas to minimize energy costs during early-season snowmaking, and developing innovative energy solutions to help manage the cost of health care in Denver hospitals.

By seeing ourselves as our stakeholders see us, and by better understanding the energy and economic needs of our customers, we transform ourselves from an energy supplier to an energy services partner, creating benefits for customers, employees and shareholders alike.

Cost Control Flexibility Growing Economy

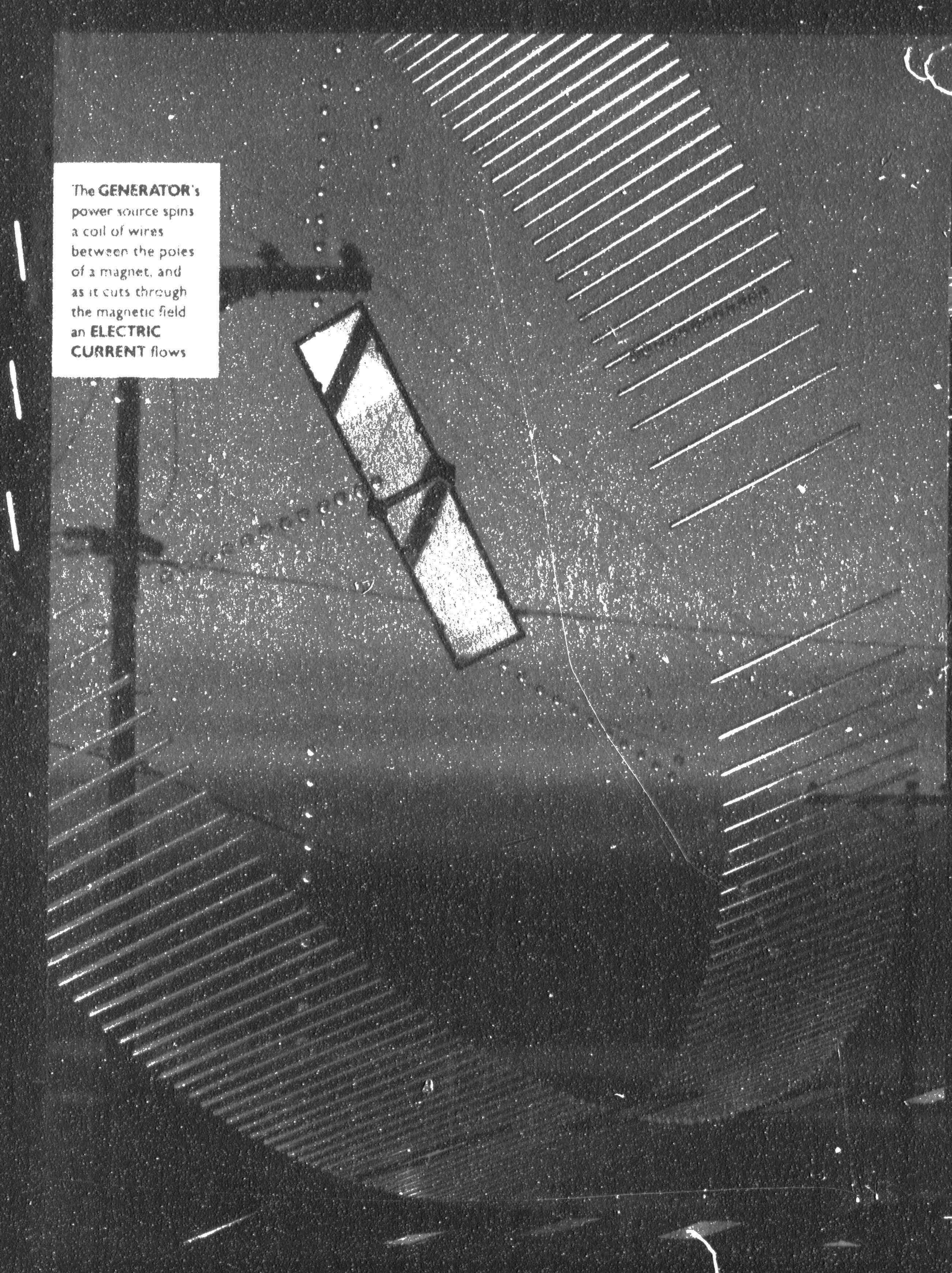
Driving Solutions

Public Service Co. is well positioned to thrive in the energy services business. While rigorous cost control is a critical element of our success in the near-term, long-term success will come by coupling cost control with improving the ways we meet the energy needs of our customers. We have begun a process to ensure that all our activities focus on the goal of becoming a truly market-driven company that evaluates all aspects of the business from the customers' perspective.

Our experience with CF&I Steel, L.P., a steelworks located in Pueblo, Colorado, and its new parent company, Oregon Steel, exemplifies the way we plan to meet market needs to retain and grow our customer base. CF&I was in Chapter 11 Bankruptcy, facing closure of its plant. This would be a blow to Colorado, mean the loss of 1,500 jobs and cost us a large and valued customer. By repricing electricity costs to encourage their investment of some $70 million for plant efficiency upgrades, energy consumption per ton of steel will drop from 760 to 570 KWH, or 25%. As the total cost per ton of steel goes down, total production will rise, thus increasing our revenues. The flexibility to structure such arrangements results in residential and other small customers being better protected economically than if the industrial customers are lost to competition, leave the state or cease operation.

All the resources are in place to justify optimism about the future. Colorado is the nation's third-fastest-growing state, with a population growth rate in 1993 that had not been seen since the 1970s. Population is growing at three times the national rate. The economy is growing at 2% a year. The 1994 opening of Denver International Airport (with its estimated 90 MW load) and the approval of the North American Free Trade Agreement offer Colorado the potential to be the Western Hemisphere's pre-eminent trading center. Colorado is rich with the resources the company needs, and the company, in turn, has the necessary financial resources to serve present and future energy services markets.

High-pressure steam strikes the **TURBINE** blades, driving them into motion, which turns heat energy into a power source for the generator.

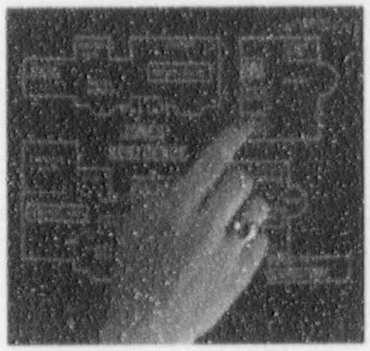


The **GENERATOR**'s power source spins a coil of wires between the poles of a magnet, and as it cuts through the magnetic field an **ELECTRIC CURRENT** flows

Restructuring Technology

Generating Currents

Energy Services



As a combination company, we are in two basic industries, each moving at different speeds. Our gas business was the first to see the break-up of the traditional industry structure. Our electric business– now composed of generation, transmission and distribution– will be next. These may well be different businesses with different customers operating under different conditions. The closer we get to this "unbundling," the more opportunity appears. For instance, we have a new information system for gas management– essentially an electronic bulletin board– that gives us data on what customers are using, what time they are using it, and other valuable information. This raw data is central to defining the real needs of our customers. In this way, Public Service Co. is an energy information company as well as an energy services company.

Our future will be shaped by two forces: market needs and technology. It is probable that the explosion in technology and services that followed the restructuring of the telephone industry will be replicated in ours.

As the structure of the industry evolves, so must our corporate structure. We plan restructuring in 1994 that will position us to compete in the evolving energy services industry. Restructuring will be based on a newly defined strategic direction. It will delve into how we are now organized to serve our customers and how we might best reorganize to more effectively meet customer needs while retaining high-quality, low-cost service.

As the dynamics of the industry evolve, so should the dynamics of regulation. Without the regulatory flexibility to allow us to compete with non-utility generators, independent power producers and even self-generation– particularly in the industrial market– more costs will be forced on to smaller customers. This will make us less competitive in those markets. We welcome competition because competition is what the market wants. We similarly welcome regulation that recognizes the reality of increasing market competition.

By forging the kinds of partnerships with regulators that we have formed with customers and by increasing the reliance on the talent and energy of our employees, we will continue to provide shareholders with growth in their investment and become the premier energy services provider our every effort is intended to achieve.

About Public Service Company of Colorado

Public Service Company of Colorado is an investor-owned electric, natural gas and thermal energy utility, which serves approximately 2.7 million people throughout Colorado and the Cheyenne, Wyoming area.

Headquartered in Denver, Colorado, the company operates eight steam-electric plants, six hydroelectric facilities, a downtown Denver thermal energy service and an extensive natural gas system that includes more than 13,900 miles of natural gas distribution mains.

The company's consolidated financial statements include the results of its subsidiary operations:

Cheyenne Light, Fuel and Power Company, an electric and natural gas company serving the Cheyenne area;

Fuel Resources Development Co., an oil and natural gas exploration, development and production company with operations throughout the Rocky Mountain Region;

Natural Fuels Corporation, a company that is building the infrastructure for natural gas vehicles and sells compressed natural gas as a transportation fuel;

WestGas InterState, Inc., a natural gas transmission company operating in Colorado and Wyoming;

WestGas Gathering, Inc., a natural gas gathering and processing company operating in Colorado;

WestGas TransColorado, Inc., a subsidiary which holds a one-third interest in a natural gas transmission company which will operate in Colorado;

Welton Properties, a company that owns and manages real estate for utility operations; and

PS Colorado Credit Corporation and **P.S.R. Investments, Inc.,** two finance subsidiaries.

Percentage of Male, Female and Minority Employees at Year-End 1992 and 1993

	Male		Female		Native American		Asian/ Pacific Islanders		Hispanic		Black		Total Minorities		White		Total	
	1992	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992	1993
Total Work Force	4,960	4,911	1,608	1,596	49	53	87	86	874	878	369	375	1,379	1,397	5,189	5,115	6,568	6,507
% of Total	75.5	75.5	24.5	24.5	0.8	0.8	1.3	1.3	13.3	13.5	5.6	5.8	21.0	21.4	79.0	78.6	100	100
Management	683	666	109	109	3	3	11	10	46	49	21	19	81	81	711	694	792	775
% of Management	86.2	85.9	13.8	14.1	0.4	0.4	1.4	1.3	5.8	6.3	2.7	2.5	10.2	10.5	89.8	89.5	100	100
Non-Management	4,277	4,245	1,499	1,487	46	50	76	76	828	829	348	356	1,298	1,311	4,478	4,421	5,776	5,732
% of Non-Management	74.0	74.1	26.0	25.9	0.8	0.9	1.3	1.3	14.3	14.5	6.0	6.2	22.5	22.9	77.5	77.1	100	100

1993 Financial Information

OPERATING STATISTICS
Public Service Company of Colorado and Subsidiaries

NATURAL GAS SERVICE STATISTICS

	1993	1992	1991	1990	1989	1988	1983
Bcf Gas Deliveries	**281.4**	245.0	232.7	210.9	202.2	194.5	177.6
% Change	**14.9%**	5.3	10.3	4.3	4.0	8.5	(6.4)%
Customers (000)	**907.4**	895.3	878.6	865.4	853.1	841.4	744.3
% Change*	**1.3%**	1.9	1.5	1.4	1.4	1.1	3.6%
Average Annual Residential Mcf Usage	**120.9**	109.5	116.8	112.0	112.7	116.3	120.2
% Change	**10.4%**	(6.3)	4.3	(0.6)	(3.1)	6.2	(4.0)%
Annual Heating Degree Days	**6,217**	5,359	5,914	5,575	5,810	5,958	6,429
% Change	**16.0%**	(9.4)	6.1	(4.0)	(2.5)	9.6	5.2%
Average Residential Revenue Per Mcf	**$3.73**	3.76	3.74	3.78	3.81	3.82	$4.61
% Change	**(0.8)%**	0.5	(1.1)	(0.8)	(0.3)	(1.5)	12.2%
Average Annual Revenue Per Residential Customer	**$450**	412	437	420	430	441	$554
% Change	**9.2%**	(5.7)	4.0	(2.3)	(2.5)	3.8	8.0%
Daily Availability–(MMcf)	**1,506**	1,596	1,601	1,575	1,595	1,517	1,459
Maximum Peak-Day Sendout (MMcf)	**1,236**	1,252	1,258	1,575	1,497	1,170	1,356
% Change	**(1.3)%**	(0.5)	(20.1)	5.2	27.9	6.9	4.1%

ELECTRIC SERVICE STATISTICS

	1993	1992	1991	1990	1989	1988	1983
Kilowatt-Hour Sales (millions)	**23,210**	21,815	20,452	20,148	19,716	19,194	15,654
% Change	**6.4%**	6.7	1.5	2.2	2.7	4.6	1.4%
Customers (000)	**1,095.7**	1,015.3	1,000.7	990.6	983.6	974.0	892.6
% Change*	**7.9%**	1.5	1.0	0.7	1.0	0.7	3.2%
Average Annual Residential Kwh Usage	**6,717**	6,533	6,563	6,445	6,348	6,403	6,076
% Change	**2.8%**	(0.5)	1.8	1.5	(0.9)	2.3	1.9%
Average Residential Revenue Per Kwh	**7.26¢**	7.20	7.07	7.02	7.11	7.18	6.45¢
% Change	**0.8%**	1.8	0.7	(1.3)	(1.0)	–	(1.1)%
Average Annual Revenue Per Residential Customer	**$488**	470	464	453	451	460	$392
% Change	**3.8%**	1.3	2.4	0.4	(2.0)	2.5	0.8%
Net Dependable System Capability at Time of Peak–Megawatts	**4,722(s)**	4,658(s)	4,168(s)	4,327(w)	3,912(s)	3,911(s)	3,512(w)
Net Firm System Peak Load (Mw)	**3,869**	3,757	3,568	3,589	3,484	3,362	2,968
% Change	**3.0%**	5.3	(0.6)	3.0	3.6	1.9	2.6%
Reserve Margin at Time of Peak	**22.0%**	24.0	16.8	20.6	12.3	16.3	18.3%
Generation by Class of Fuel:							
Coal	**98.5%**	98.7	98.1	98.3	92.9	91.1	93.4%
Natural Gas	**1.5%**	1.3	1.7	1.6	2.9	3.5	0.9%
Oil	**–**	–	0.2	0.1	0.2	0.1	0.4%
Nuclear	**–**	–	–	–	4.0	5.3	5.3%
Average Cost Per Unit of Fuel:							
Coal–Ton	**$21.03**	21.14	22.40	21.44	21.41	22.39	$23.87
Natural Gas–Mcf	**$ 2.32**	2.07	1.98	2.07	2.16	2.27	$ 4.07
Oil–Barrel	**$29.50**	26.84	27.16	27.85	30.31	28.65	$27.35
Average Fuel Cost Per MMBTU	**$ 1.10**	1.11	1.20	1.17	1.17	1.25	$ 1.23

* The criteria for counting customers was modified during 1993 with the implementation of a new Customer Information System.
(s) summer peak load
(w) winter peak load

FINANCIAL AND STATISTICAL DATA

Public Service Company of Colorado and Subsidiaries

(Millions of Dollars Except as Noted)

	1993	1992	1991	1990	1989	1988	198[illegible]
Operating Revenues:							
Electric	**$1,337.1**	1,260.8	1,180.5	1,145.9	1,139.5	1,116.0	$ 853.7
Gas	**628.3**	568.9	58[illegible].6	561.7	577.3	591.4	761.6
Other	**33.3**	32.6	26.8	26.3	23.9	23.0	13.3
Total Revenues	**$1,998.7**	1,862.3	1,794.9	1,733.9	1,740.7	1,75[illegible]	$1,628.6
Net Income	**$157.4**	136.6	149.7	146.1	148.8	125.0	$106.4
Preferred Dividend Requirements	**12.1**	12.1	12.2	12.4	12.6	12.8	16.7
Earnings Available for Common Stock	**$145.3**	124.5	137.5	133.7	136.2	112.2	$89.7
Earnings Per Weighted Average Share	**$2.43**	2.16	2.48	2.49	2.5[illegible]	2.14	$1.86
Dividends Per Share:							
Paid	**$2.00**	2.00	2.00	2.00	2.00	2.[illegible]	$1.82
Declared	**$2.00**	2.00	2.00	2.00	2.00	2.00	$1.84
Common Stock Outstanding:							
Weighted average (000)	**59,695**	57,558	55,471	53,626	52,559	52,457	48,135
Year-end (000)	**60,457**	58,477	56,294	54,320	52,807	52,458	49,182
Total Assets	**$4,058**	3,760	3,463	3,234	3,054	2,995	$2,665
Common Equity	**$1,184**	1,101	1,034	964	905	865	$ 821
Preferred Stock:							
Subject to mandatory redemption at par	**43**	43	44	46	49	52	88
Not subject to mandatory redemption	**140**	140	140	140	140	140	14[illegible]
Long-Term Debt	**1,135**	1,197	900	896	913	944	886
Short-Term Borrowings*	**338**	256	297	259	186	162	4[illegible]
Total Capitalization	**$2,840**	2,737	2,415	2,305	2,193	2,163	$1,979
Capitalization Ratios–Year-End:							
Common equity	**41.7%**	40.2	42.8	41.8	41.2	40.0	41.5%
Preferred stock (Incl. due within 1 yr.)	**6.5%**	6.8	7.7	8.2	8.6	8.9	11.6%
Long-term debt (Incl. due within 1 yr.)	**42.0%**	43.8	41.2	40.7	41.7	43.6	45.9%
Notes payable and commercial paper	**9.8%**	9.2	8.3	9.3	8.5	7.5	1.0%
Construction Expenditures	**$293.5**	261.7	260.7	261.2	174.4	162.8	$195.5
% of Total capitalization	**10.3%**	9.6	10.8	11.3	8.0	7.5	9.9%
Cash Generated Internally**	**$149.1**	146.3	177.7	174.6	172.3	192.8	$132.6
% of Construction expenditures***	**52.2%**	57.5	69.4	67.7	99.7	118.8	71.0%
Rates of Return Earned:							
Total capitalization (Oper. income)	**9.9%**	9.1	10.1	10.3	11.3	10.2	9.2%
Avg. common equity (Net to common)	**12.7%**	11.7	13.8	14.3	15.4	13.0	11.2%
Pretax Coverage of Interest Expense	**2.54x**	2.43	2.94	3.07	3.02	2.81	3.42x
Effective Income Tax Rate	**28%**	28	32	34	31	33	46.8%
Payout Ratio on Dividends Paid	**82.3%**	92.6	80.6	80.3	77.2	93.5	97.8%
Book Value Per Share–Year-End	**$19.59**	18.83	18.38	17.74	17.13	16.49	$16.70
Market Price Per Share–Year-End	**$ 32¼**	28[illegible]	27	23[illegible]	26[illegible]	21[illegible]	$ 18[illegible]
Number of Employees–Year-End	**6,507**	6,568	6,565	6,611	6,636	6,559	6,857

* Includes debt due within one year, notes payable and commercial paper and preferred stock subject to mandatory redemption within one year.

** Cash provided from operations net of cash used for dividends. 1983 calculated as funds generated internally.

*** Calculated as cash provided from operations net of cash used for dividends divided by construction expenditures net of AFDC-equity component. 1983 calculated as funds generated internally as a % of net construction expenditures.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Public Service Company of Colorado and Subsidiaries

Overview

Utility Operations

During 1993, Public Service Company of Colorado (the Company) continued to pursue the strategy of focusing on its core electric and gas businesses. Such businesses are in a transition period as, in general, they are expected to be increasingly competitive as a result of a variety of regulatory, economic and technological developments. The following summary highlights several events that have occurred which serve to contribute to this changing environment.

The Company's retail electric business faces increasing competition due to the ability of industrial and large commercial customers to generate their own electric energy requirements, to substitute fuels such as natural gas for heating and/or cooling purposes or to relocate their facilities to a lower cost environment. The Company's retail natural gas business, in the industrial and large commercial sectors, has undergone a transition from sales of gas to transportation of gas sold to others, without any significant effect on net income to date.

On November 26, 1993, as part of a general rate case filed earlier in the year, The Public Utilities Commission of the State of Colorado (CPUC) issued its final written decision, reducing the authorized level of the Company's total annual base electric, gas and steam rate revenues by approximately $5.2 million on a basis of a rate of return on regulated rate base of 9.4%, including a rate of return on regulated common equity of 11%. The new rates became effective December 1, 1993. The Company had requested an $81.6 million increase in electric, gas and steam revenues on the basis of a rate of return on regulated rate base of 10.5%, including a rate of return on regulated common equity of 13%. The CPUC rejected the Company's proposed use of a fully forecasted future test year in the establishment of revenue requirements and instead continued the use of an historical test year using the twelve months ended September 30, 1992.

In response to the outcome of the 1993 rate case and in order to operate more effectively in a competitive environment, the Company has adopted certain short- and long-term strategies to lower operating costs and achieve adequate earnings levels. Generally, the short-term strategies include the implementation of cost reduction programs designed to reduce operating and maintenance expenses, at a minimum, to the approximate level included in the recently established rates. On January 25, 1994, as part of this short-term strategy, the Company's Board of Directors approved an early retirement/severance program under which approximately 600 employees are eligible to participate. Additionally, voluntary and involuntary programs will be instituted following the implementation of the early retirement program. The estimated cost of the early retirement/severance programs range from $25 to $32 million. The Company intends to amortize such costs to expense over a period not to exceed approximately five years in accordance with anticipated regulatory treatment.

Concurrently, and from a longer-term perspective, the Company has initiated an extensive review of its business processes to better position itself to more effectively address the changes in the industry and the energy marketplace as well as the diverse needs of its customers.

Although the Company is operating in an increasingly competitive environment, it believes it will continue to be subject to traditional rate-regulated principles, which include cost-of-service regulation and the recovery of all costs previously deferred in accordance with regulatory approvals for the foreseeable future. Furthermore, the Company is actively participating in CPUC dockets addressing changes to the current regulatory environment. The CPUC has opened separate dockets to investigate issues relating to incentive regulation and integrated resource planning. In addition, the Company has developed and implemented, following CPUC approval, several demand-side management programs.

Nonutility Assets

Following approval by the Company's Board of Directors, the divestiture of a substantial portion of Fuel Resources Development Co.'s (Fuelco) (an oil and gas exploration and production subsidiary) oil and gas related production properties has been completed. A purchase and sale contract for the remaining property is being negotiated with closing anticipated no later than the end of the first quarter of 1994. In December 1993, the Company recorded the effects of the disposition of all properties, including the 1994 anticipated sale, and additional costs expected to be incurred through the close of operations. The effects of these transactions had no material impact on the Company's 1993 results of operations or financial position.

Additionally, during 1992 as part of an effort to divest nonutility investments, the Company discontinued its participation in Synhytech, a methane gas conversion project, and sold its downtown Denver real estate properties owned by Bannock Center Corporation (BCC). As a result, the Company recognized two significant charges totalling $25.2 million after-tax, or 44 cents per share, in 1992. During 1993, both subsidiaries were dissolved.

The following discussion refers to the consolidated financial statements and related notes of the Company and should be read in conjunction with such statements and notes.

Earnings

Earnings per share were $2.43, $2.16 and $2.48 during 1993, 1992 and 1991, respectively. The full-year effect of the April, 1992 addition of four new wholesale electric customers, coupled with the positive impact of weather-related factors during 1993, served to increase electric sales and gas deliveries. The positive impact resulting from higher electric Kwh sales and gas Mcf deliveries in 1993 were offset, in part, by increased operating and maintenance expenses. The positive effects in 1992 of increased revenues from higher electric sales, as compared to 1991, primarily associated with the four new wholesale electric customers and decreased

other operating expenses, were to a large extent offset by the charges to earnings related to the divestiture of the Company's nonutility investments, discussed above.

Electric Sales, Revenues and Energy Costs

Electric operating revenues increased $76.3 million in 1993 and $80.3 million in 1992, when compared to the respective preceding years, reflecting increased sales volumes to both retail and wholesale customers and the net effects of the Electric Cost Adjustment (ECA) mechanism on prices of units sold. The following table details the annual changes in revenues when compared to revenues for the preceding year for these components:

	(Millions of Dollars) 1993	1992
Electric revenues:		
Base rate changes	**$ 4.4**	$(17.0)
Rate rider for decommissioning	**6.8**	—
Electric cost adjustment	**2.2**	37.8
New wholesale customers	**27.0**	43.0
Sales volume and other changes	**35.9**	16.5
Net increase	**$76.3**	$ 80.3

Base rates are only changed through rate proceedings with the Company's regulatory agencies. Effective July 1, 1993, a 1.29% electric revenue increase (an approximate $13.9 million annual revenue increase) associated with the recovery of nuclear decommissioning costs was implemented (see Note 2. Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements). Over the past several years, the Company has been involved in numerous settlement agreements with the CPUC and other parties which generally have reduced electric revenues. Prior to December 1, 1993 and during 1992 and 1991, there were two separate electric revenue reductions in place: a 1.41% reduction designed to adjust for an earnings imbalance between the electric and gas departments and a 3.38% reduction related to the settlement of a rate case filed in early 1991. On November 26, 1993, the CPUC issued its final rate case decision which requires an overall revenue reduction of approximately $5.2 million, after giving effect to the reductions under prior rate settlements. Such reduction is comprised of a $13.1 million electric revenue decrease offset by a $7.1 million gas revenue increase (discussed below) and a $0.8 million steam revenue increase.

The increases in electric Kwh sales of 6.4% and 6.7% for 1993 and 1992, when compared to the respective preceding years, is primarily due to the April, 1992 addition of the four new wholesale customers previously served by Colorado-Ute Electric Association, Inc. (Colorado-Ute). In addition, colder weather experienced during 1993 as well as an increase in economy sales to other utilities also served to increase electric Kwh sales. Generally, however, economy sales provide a smaller profit margin than sales to the Company's other classes of customers.

The Company and Cheyene Light, Fuel and Power Company (Cheyenne) have cost adjustment mechanisms which recognize the majority of the effects of increases and decreases in fuel used in generation and purchased power costs and allow recovery of such costs on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1993, 1992 and 1991 had little impact on net income.

Total electric energy costs increased 7.7% in 1993 when compared to 1992. Purchased power expense increased in 1993 due to a 10.7% increase in Kwh purchases, with minimal change in the energy cost per Kwh. The increase in fuel used in generation expense was primarily due to a 3.3% increase in generation at the Company's power plants. Generation levels for 1993 and 1992, when compared to the respective preceding years, increased primarily due to the April, 1992 purchase of additional generating facilities from Colorado-Ute. Total electric energy costs increased 9.5% in 1992, when compared to 1991, primarily due to an increase in generation and higher per unit costs for power purchased.

The Company has continued to experience moderate growth in customers in both 1993 and 1992. The Company anticipates that further customer growth will be in the 1.2% range in the near-term.

Gas Sales, Revenues and Purchased Costs

Gas operating revenues increased $59.4 million in 1993 and decreased $18.7 million in 1992, when compared to the respective preceding years, primarily due to changes in total gas sales. The following table details the annual changes in revenues when compared to revenues for the preceding year for these components:

	(Millions of Dollars) 1993	1992
Gas revenues:		
Base rate changes	**$ 0.4**	$ —
Gas cost adjustment	**0.2**	2.1
Increase in transport, gathering and processing	**5.1**	4.2
Sales volume and other changes	**53.7**	(25.0)
Net increase (decrease)	**$59.4**	$(18.7)

Higher gas revenues in 1993 were attributable to a 10.5% increase in sales due to colder weather experienced in 1993 as compared to 1992. The decline in gas operating revenues in 1992, as compared to 1991, was primarily due to a 5.2% decrease in gas sales caused by warmer-than-normal weather.

Total gas deliveries (which include gas sales) increased 14.9% in 1993 and 5.3% in 1992, when compared to the respective preceding years, primarily due to increased gas gathering and transport volumes. Although gas sales have fluctuated in recent years, the Company continues to experience growth in transportation services and gathering and processing activities. The per unit fee charged for transportation services, while significantly less than the per unit fee charged for a sale to a similar customer, provides an operating margin approximately equivalent to the margin earned on gas sold. In addition and similar to gas transportation services, the per unit fee charged for gathering and processing activities is also significantly less than the per unit amount charged for the sale

of gas. Therefore, increases in such activities will not have as great an impact on gas revenues as would increases in deliveries from the sale of gas, but will have a positive impact on operating margin. As a result of the Company's 1993 rate case discussed above, gas base rate revenues are expected to increase $7.1 million (or approximately 1.2%) on an annual basis, effective December 1, 1993.

The Company and its regulated subsidiaries have in place Gas Cost Adjustment (GCA) mechanisms for gas sales, which recognize the majority of the effects of changes in the cost of gas purchased for resale and adjust revenues to reflect such changes in cost on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1993 and 1992, when compared to the respective preceding year, had little impact on net income. However, the fluctuations in gas sales affect the amount of gas the Company must purchase and, therefore, affect gas purchased for resale expense along with increases and decreases in the per unit cost of gas. The increase in gas purchased for resale for 1993, when compared to 1992, reflects an increase in the amount of gas purchased, primarily attributable to the increased gas sales, as well as a slight increase in the per unit cost of gas. The decline in 1992 purchased gas costs was due to lower sales offset by an increase in the per unit cost of gas when compared to 1991.

The Company continued to experience moderate growth in customers in 1993 and 1992. The Company anticipates that further customer growth will be approximately 1.9% during the near-term.

Non-Fuel Operating Expenses

Other operating and maintenance expenses increased for 1993 primarily due to increased labor and benefit costs and a $3.1 million after-tax write-off of the Company's investment in the Templeton Gap methane recycling facility. The decline in other operating expenses in 1992, when compared to 1991, is primarily attributable to certain cost containment efforts instituted throughout the Company coupled with lower nuclear related costs. This decline was offset to a certain degree by costs incurred to operate assets acquired as part of the Colorado-Ute asset acquisition. Other non-fuel operating expenses in 1992 also included the recognition of charges to earnings associated with the Synhytech and BCC transactions of approximately $26.9 million and $11.4 million, respectively.

Higher 1993 and 1992 depreciation and amortization expense, when compared to the respective preceding years, reflects the effects of additional assets acquired from Colorado-Ute and other property additions. The 1993 depreciation and amortization expense also includes the amortization of the decommissioning regulatory asset associated with Fort St. Vrain , which began July 1, 1993, along with the collection of such costs.

The increase in income tax expense for 1993 reflects a 1% increase in the Federal tax rate and higher pre-tax income, offset by the $1.9 million benefit realized from the adoption of Statement of Financial Accounting Standards No. 109–"Accounting for Income Taxes" (SFAS 109). The decline in income tax expense in 1992, when compared to 1991, was primarily attributable to lower pre-tax income.

Interest on long-term debt increased $5.5 million in 1993 over 1992, reflecting the effect of the issuance of $250 million in First Mortgage Bonds in April, 1992 to finance the Colorado-Ute asset acquisition as well as the issuance of $50 million in medium-term notes during the fourth quarter of 1992, offset slightly by the effects of certain 1993 long-term debt refinancings at lower interest rates. The increase in interest expense in 1992, when compared to 1991, was the result of the debt issuances noted above.

Recently Issued Accounting Standards Not Yet Adopted

In November 1992, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 112–"Employers' Accounting for Postemployment Benefits" (SFAS 112), which establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (postemployment benefits). SFAS 112 became effective January 1, 1994, and the Company has estimated its benefit obligation to be approximately $32 million, assuming a 7.5% discount rate. The Company believes it is probable that it will receive CPUC approval to recover these costs in future rates and, therefore, the application of the new standard will not have a material impact on the Company's results of operations or financial position as a regulatory asset and a corresponding liability will be established on the consolidated balance sheet.

Commitments and Contingencies

Issues relating to Fort St. Vrain, environmental matters and postretirement benefits other than pensions are discussed in Notes 2, 8 and 10, respectively, in the Notes to Consolidated Financial Statements.

As previously discussed, on November 26, 1993, the CPUC issued its final decision in connection with the 1993 rate case denying the Company any rate relief and lowering the Company's overall revenue requirements by approximately $5.2 million. The Company is implementing strategies which include, among other things, endeavoring to reduce operating expenses, at a minimum, to the historic test period level. It is possible, however, that despite such efforts, the Company could be required to issue increasing amounts of short-term and long-term securities to fund cash requirements and that the Company's results of operations and financial position could be adversely affected over time.

The level of dividends on the Company's common stock is dependent upon the Company's results of operations, financial position and other factors and is evaluated quarterly by the Board of Directors. The Company is subject to numerous uncertainties, particularly the success of implementing strategies adopted as a result of the 1993 rate case which was discussed above and issues relating to Fort St. Vrain, the resolution of which could influence such evaluation.

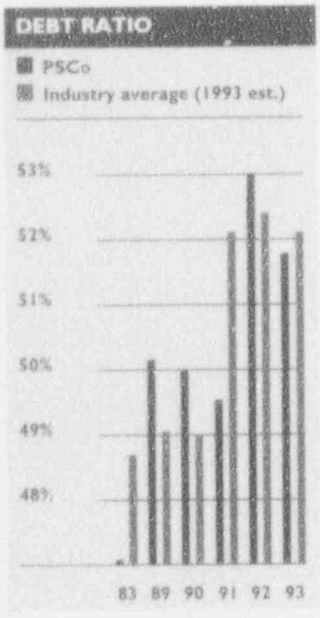
Liquidity and Capital Resources

Cash Flows

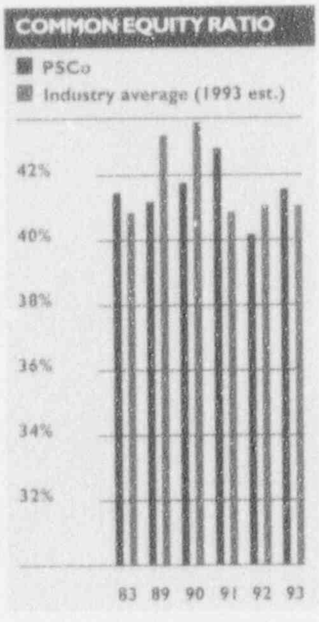
Net cash provided by operating activities increased $7.1 million during 1993, primarily due to increased earnings and higher depreciation and amortization related to property additions, including the acquisition of the Colorado-Ute assets. Although the Company collected approximately $6 million in decommissioning costs from customers in 1993, yearly expenditures of approximately $50 million associated with the decommissioning of Fort St. Vrain will continue to reduce operating cash flows through 1995.

Cash used in investing activities decreased $192.6 million for 1993, primarily due to the 1992 acquisition of Colorado-Ute assets. In addition, in 1993 three new wholesale customers prepaid 100%, or approximately $24.9 million, of their surcharge associated with the Colorado-Ute acquisition. In comparing 1993 to 1992, however, this was offset by the 1992 receipt of approximately $75 million in loan proceeds from insurance policies by one of the Company's subsidiaries.

Cash provided by financing activities decreased approximately $247.7 million during 1993, primarily due to the 1992 issuance of $250 million of First Mortgage Bonds related to the acquisition of the Colorado-Ute assets. On April 20, July 1, and November 23, 1993, the Company issued $79.5 million and $50 million of First Mortgage Bonds, and $134.5 million of First Collateral Trust Bonds, respectively. All 1993 bond proceeds were used to refund outstanding, higher cost long-term debt and, therefore, resulted in minimal impact on the financing cash flows of the Company. An additional debt refinancing of approximately $212.7 million was completed in early 1994.



Proportion of borrowed funds to the total amount invested in the Company.



Shareholders' investment as a percent of the total amount invested in the Company.

Prospective Capital Requirements and Sources

At December 31, 1993, the Company and its subsidiaries estimated the cost of their construction programs, including Allowance for Funds Used During Construction (AFDC) and other capital requirements, in 1994, 1995 and 1996 to be as follows:

	(Thousands of Dollars) 1994	1995	1996
Company:			
Electric			
Production*	$121,280	$144,035	$ 94,027
Transmission	44,575	84,476	47,728
Distribution	69,191	69,073	66,980
Gas	62,660	77,233	78,146
General**	65,574	86,813	40,082
Subtotal	363,280	461,630	326,963
Subsidiaries	15,455	14,857	26,207
Total construction	378,735	476,487	353,170
Less: AFDC	11,470	18,580	13,974
Add: Sinking funds and debt maturities	365,221	38,703	80,982
Add: Fort St. Vrain decomissioning	40,748	42,791	–
Total capital requirements	$773,234	$539,401	$420,178

* Capital requirements for Electric Production include $74 million for Fort St. Vrain repowering.

** Capital requirements for General include assets leased under a leasing program.

The construction programs of the Company and its subsidiaries are subject to continuing review and adjustment. In particular, actual construction expenditures for the electric system may vary from the estimates due to changes in projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting the Company's long-term energy needs. In addition, actual decommissioning and defueling expenses may exceed the estimates due to a variety of factors discussed in Note 2 in the Notes to Consolidated Financial Statements.

At December 31, 1993, the Company and its subsidiaries estimated that their 1994-1996 capital requirements would be met principally with a combination of funds from external sources and with funds from operations. The Company and its subsidiaries may meet their external capital requirements through the issuance of first collateral trust bonds, preferred and/or common stock, by increasing the level of borrowing under PS Colorado Credit Corporation's (PSCCC) medium-term note program or through short-term borrowing under committed and uncommitted bank borrowing arrangements discussed below. The financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the construction plans of the Company and its subsidiaries.

The Company's Automatic Dividend Reinvestment and Common Stock Purchase Plan allows its shareholders to purchase additional shares of common stock of the Company through the reinvestment of cash dividends and the purchase of additional shares of common stock with optional cash payments. The proceeds from the dividend

reinvestment plan will also provide funds to help meet the capital requirements of the Company.

At December 31, 1993, the Company and its subsidiaries had temporary cash investments of $9.57 million.

As of December 31, 1993, PSCCC had borrowed $167.3 million in short-term debt, for use primarily in the purchase of the Company's customer accounts receivable and fossil fuel inventories. PSCCC may periodically convert short-term debt to medium-term notes. As of December 31, 1993, PSCCC had no medium-term notes outstanding. The level of financing of PSCCC is tied directly to daily changes in the level of the Company's outstanding customer accounts receivable and monthly changes in fossil fuel inventories. The Company expects that the amount of financing associated with PSCCC will vary minimally from year-to-year although seasonal fluctuations in the level of assets will cause corresponding fluctuations in the level of associated financing.

In 1990, the Company filed a registration statement with the Securities and Exchange Commission (SEC) for the issuance of $500 million principal amount of first mortgage bonds of which $200 million was designated for a secured medium-term note program. As of December 31, 1993, $141.5 million principal amount of medium-term notes had been issued and $250 million of first mortgage bonds had been issued. In 1993, the Company filed a registration statement with the SEC for the issuance of $322.667 million principal amount of first collateral trust bonds, for the purpose of refunding outstanding debt securities and for the payment of short-term indebtedness incurred for such purposes, of which $212.667 million principal amount has been issued.

The Company's 1939 Indenture, which is a mortgage on the Company's electric and gas properties, permits the issuance of additional first mortgage bonds to the extent of 60% 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 1939 Indenture also permits the issuance of additional bonds on the basis of retired first mortgage bonds, in some cases with no requirement to satisfy such net earnings test. At December 31, 1993, the amount of net additions would permit (and the net earnings test would not prohibit) the issuance of approximately $103 million of new bonds (in addition to the $200 million principal amount of secured medium-term notes discussed above) at an assumed annual interest rate of 7.6%. At February 22, 1994, the amount of retired bonds would permit the issuance of $834 million of new bonds.

In 1993, the Company entered into a new Indenture, which is a second mortgage on the Company's electric properties. Generally, so long as the Company's 1939 Indenture remains in effect, first collateral trust bonds will be issued under the 1993 Indenture on the basis of the deposit with the trustee of an equal principal amount of first mortgage bonds issued under the 1939 Indenture. If the bonds issued under the 1939 Indenture are to be issued on the basis of property additions, first collateral trust bonds may be issued under the 1993 Indenture only if net earnings before depreciation, taxes on income, interest expenses and non-recurring charges for a recent twelve-month period are at least 2 times annual interest requirements on all first mortgage bonds (other than bonds held by the trustee under the 1993 Indenture) and all first collateral trust bonds to be outstanding. As of January 31, 1994, coverage under the net earnings test was in excess of 5 times such annual interest requirements.

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, 1993, gross income available under this requirement would permit the Company, if allowed under the provisions of the Company's Restated Articles of Incorporation, to issue approximately $2.2 billion of additional preferred stock at an assumed annual dividend rate of 6.5%. Coverage of gross income to interest charges was 4.3 at December 31, 1993.

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 1) the total principal amount of all bonds or other securities representing secured indebtedness of the Company, then outstanding, and 2) the total of the capital and surplus of the Company, as then recorded on its books. At December 31, 1993, the Company had outstanding unsecured indebtedness, including subsidiary indebtedness with the credit support of the Company, in the amount of $109.6 million. The maximum amount permitted under this limitation was approximately $375.6 million at December 31, 1993.

At December 31, 1993, the Company and certain of its subsidiaries had arrangements for bank lines of credit totaling $300 million in committed lines, of which $23.1 million was then available. On January 3, 1994, the Company established uncommitted lines of credit totaling $25 million, which expire on December 31, 1994. The Company could generally borrow under the uncommitted pre-approved lines of credit upon request; however, the banks have no firm commitment to make such loans.

On November 22, 1993, the Company, PSCCC and certain subsidiaries extended the credit facility jointly entered into on February 8, 1991, and as subsequently amended. The credit facility with several banks provides $300 million in committed bank lines of credit. The credit facility, which is used primarily to support the issuance of commercial paper by the Company and PSCCC, alternatively provides for direct borrowing thereunder. Under the current extension, Cheyenne, 1480 Welton, Inc., Fuelco, PSR Investments, Inc. and

WestGas Gathering, Inc. were provided access to the credit facility under a $125 million aggregate sub-limit with direct borrowings guaranteed by the Company. Generally, the banks participating in the credit facility would have no obligation to continue their commitments if there has been a material adverse change in the business or financial condition of the Company and its subsidiaries taken as a whole that would prevent the Company and its subsidiaries from performing their obligation under the credit facility. The credit facility expires April 1, 1994. However, the Company expects to renew the credit facility at that time (see Note 7. Bank Lines of Credit and Compensating Bank Balances in the Notes to Consolidated Financial Statements).

Natural Fuels Corporation had a committed line of credit in the amount of $4 million, which expired March 1, 1993, and was not renewed.

REPORT OF MANAGEMENT

Public Service Company of Colorado and Subsidiaries

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 accompanying financial statements have been audited by Arthur Andersen & Co., independent public accountants. Management has made available to Arthur Andersen & Co. all the Company's and its subsidiaries' financial records and related data and has provided to them representations we believe to be valid and appropriate.

The Company maintains a system of internal control over financial reporting, which is designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation of reliable published financial statements. The system includes a documented organizational structure and division of responsibility, established policies and procedures including a code of conduct to foster a strong ethical climate, which are communicated throughout the Company, and the careful selection, training and development of our people. Internal auditors monitor the operation of the internal control system and report findings and recommendations to management and the Audit Committee of the Board of Directors, and corrective actions are taken to address control deficiencies and other opportunities for improving the system as they are identified. The board, operating through its Audit Committee, which is composed entirely of directors who are not officers or employees of the Company, provides oversight to the financial reporting process.

There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even an effective internal control system can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, internal control system effectiveness may vary over time.

The Company assessed its internal control system as of December 31, 1993 in relation to criteria for effective internal control over financial reporting described in "Internal Control–Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of its assessment, the Company believes that, as of December 31, 1993, the Company's system of internal control over external financial reporting met those criteria.

W. Wayne Brown

W. Wayne Brown
Principal Accounting Officer

D. D. Hock
Chief Executive Officer

February 16, 1994

REPORTS OF THE AUDIT COMMITTEE AND INDEPENDENT PUBLIC ACCOUNTANTS

Public Service Company of Colorado and Subsidiaries

Report of the Audit Committee of the Board of Directors

The Board of Directors of the Company addresses its oversight responsibility for the consolidated financial statements through its Audit Committee. The Audit Committee meets regularly with the independent certified public accountants and the internal auditor to discuss results of their audit work and their evaluation of the adequacy of the internal controls and the quality of financial reporting.

In fulfilling its responsibilities in 1993, the Audit Committee recommended to the Board of Directors, subject to shareholder approval, the selection of the Company's independent certified public accountants. The Audit Committee reviewed the overall scope and specific plans of the independent certified public accountants' and internal auditor's respective audit plans, and discussed the independent certified public accountants' management letter recommendations, approved their general audit fees, and reviewed their non-audit services to the Company.

The committee meetings are designed to facilitate open communications between internal auditing, independent certified public accountants, and the Audit Committee. To ensure auditor independence, both the independent certified public accountants and internal auditor have full and free access to the Audit Committee.

J. Michael Powers

J. Michael Powers, Chairman
Audit Committee

February 16, 1994

Report of Independent Public Accountants

The Board of Directors and Shareholders of Public Service Company of Colorado

We have audited the accompanying consolidated balance sheets of Public Service Company of Colorado (a Colorado corporation) and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Public Service Company of Colorado and subsidiaries as of December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As more fully discussed in Note 2 to the consolidated financial statements, realization of the Company's investment in its Fort St. Vrain Nuclear Generating Station (approximately $63.4 million at December 31, 1993), as well as the regulatory asset representing the tax effects of prev[illegible] recognized tax deductions associated with such inv[illegible] for which no deferred taxes were required to be [illegible] (approximately $12.4 million at December 31, [illegible]), is primarily dependent on the Company's ability to repower the facility as a natural gas fired plant, the eventual outcome of which cannot be determined at this time. In addition, as more fully discussed in Note 2 to the consolidated financial statements, the adequacy of the Company's recorded liability for defueling and decommissioning its Fort St. Vrain Nuclear Generating Station (approximately $93.1 million at December 31, 1993) is primarily dependent on assurances that the dismantlement and decommissioning of the Fort St. Vrain Nuclear Generating Station can be accomplished at currently estimated costs and that the spent fuel storage and shipment issues are successfully resolved. The outcome of the above issues cannot be determined at this time. The accompanying financial statements do not include any adjustments that might result from the outcome of these uncertainties.

As more fully discussed in Notes 10 and 12 to the consolidated financial statements, effective January 1, 1993, the Company changed its methods of accounting for postretirement benefits other than pensions and for income taxes.

Arthur Andersen & Co.

Arthur Andersen & Co.
Denver, Colorado

February 16, 1994

CONSOLIDATED STATEMENTS OF INCOME

Public Service Company of Colorado and Subsidiaries

Years ended December 31, 1993, 1992 & 1991

	(Thousands of Dollars Except Per Share Data)		
	1993	1992	1991
Operating Revenues:			
Electric	**$1,337,053**	$1,260,769	$1,180,501
Gas	**628,324**	568,886	587,609
Other	**33,308**	32,618	26,794
	1,998,685	1,862,273	1,794,904
Operating Expenses:			
Fuel used in generation	**194,918**	182,832	177,365
Purchased power	**396,953**	366,949	323,793
Gas purchased for resale	**384,393**	343,188	365,991
Other operating expenses	**376,686**	346,368	361,610
Maintenance	**76,229**	72,540	67,216
Termination of Synhytech project (Note 3)	**-**	26,893	-
Loss on sale of real estate investments (Note 3)	**-**	11,370	-
Depreciation and amortization	**140,804**	127,317	111,728
Taxes (other than income taxes) (Note 13)	**86,775**	82,040	74,335
Income taxes (Note 12)	**60,994**	53,149	69,288
	1,717,752	1,612,646	1,551,326
Operating Income	**280,933**	249,627	243,578
Other Income and Deductions:			
Allowance for equity funds used during construction (Note 1)	**8,119**	7,378	4,763
Miscellaneous income and deductions–net	**(1,355)**	734	2,889
	287,697	257,739	251,230
Interest Charges:			
Interest on long-term debt	**98,089**	92,581	81,666
Amortization of debt discount and expense less premium	**2,018**	1,790	1,827
Other interest	**34,778**	30,669	22,718
Allowance for borrowed funds used during construction (Note 1)	**(4,548)**	(3,924)	(4,674)
	130,337	121,116	101,537
Net Income	**157,360**	136,623	149,693
Dividend Requirements on Preferred Stock	**12,031**	12,077	12,234
Earnings Available for Common Stock	**$ 145,329**	$ 124,546	$ 137,459
Shares of Common Stock Outstanding (thousands):			
Year-end	**60,457**	58,477	56,294
Weighted average	**59,695**	57,558	55,471
Earnings Per Weighted Average Share of Common Stock Outstanding	**$2.43**	$2.16	$2.48
Dividends Per Share of Common Stock:			
Paid	**$2.00**	$2.00	$2.00
Declared	**$2.00**	$2.00	$2.00

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

CONSOLIDATED BALANCE SHEETS

Public Service Company of Colorado and Subsidiaries

December 31, 1993 & 1992

Assets	1993	1992
	(Thousands of Dollars)	
Property, Plant and Equipment, at Cost:		
Electric	**$3,390,442**	$3,231,876
Gas	**929,718**	898,952
Steam and other	**75,288**	87,458
Common to all departments	**356,633**	280,416
Construction in progress	**178,959**	236,179
	4,931,040	4,734,881
Less: Accumulated depreciation	**1,801,323**	1,719,913
	3,129,717	3,014,968
Fort St. Vrain related property (Note 2)	**79,023**	79,323
Less: Accumulated depreciation	**15,604**	16,782
	63,419	62,541
Total Property, Plant and Equipment	**3,193,136**	3,077,509
Investments, at Cost	**12,668**	19,225
Current Assets:		
Cash and temporary cash investments	**18,038**	51,155
Accounts receivable, less reserve for uncollectible accounts ($3,276 at December 31, 1993; $3,388 at December 31, 1992)	**155,456**	151,643
Accrued unbilled revenues (Note 1)	**76,983**	72,795
Recoverable purchased gas and electric energy costs-net (Note 1)	**60,692**	45,640
Materials and supplies, at average cost	**77,732**	81,002
Fuel inventory, at average cost	**35,484**	33,573
Gas in underground storage, at cost (LIFO)	**41,130**	14,393
Prepaid expenses	**12,716**	20,984
Current portion of accumulated deferred income taxes (Note 12)	**4,201**	–
Current portion of recoverable nuclear decommissioning costs (Note 2)	**11,125**	6,151
Other	**864**	2,191
Total Current Assets	**494,421**	479,527
Deferred Charges:		
Unamortized debt expense	**28,985**	20,361
Regulatory assets:		
Recoverable nuclear decommissioning costs (Note 2)	**107,294**	118,293
Income taxes (Notes 2 and 12)	**132,647**	–
Employees' postretirement benefits other than pensions (Note 10)	**25,855**	–
Pension benefits (Note 10)	**23,149**	15,629
Other	**39,445**	29,039
	357,375	183,322
Total Assets	**$4,057,600**	$3,759,583

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

Capital and Liabilities	1993	(Thousands of Dollars) 1992
Common Equity:		
Common stock (Note 4)	$ 910,848	$ 853,322
Retained earnings	273,335	247,725
	1,184,183	1,101,047
Preferred Stock (Note 4):		
Not subject to mandatory redemption	140,008	140,008
Subject to mandatory redemption at par	42,878	43,078
Long-Term Debt (Note 5)	1,135,344	1,196,959
	2,502,413	2,481,092
Noncurrent Liabilities:		
Defueling and decommissioning liability (Note 2)	45,220	88,124
Employees' postretirement benefits other than pensions (Note 10)	28,145	–
	73,365	88,124
Current Liabilities:		
Notes payable and commercial paper (Note 6)	276,875	250,626
Long-term debt due within one year	58,324	2,820
Preferred stock subject to mandatory redemption within one year (Note 4)	2,576	2,576
Accounts payable	214,599	182,690
Dividends payable	33,234	32,248
Customers' deposits	16,225	16,807
Accrued taxes	70,796	80,312
Accrued interest	29,507	31,032
Current portion of defueling and decommissioning liability (Note 2)	47,887	52,896
Other	64,664	54,512
Total Current Liabilities	814,687	706,519
Deferred Credits:		
Customers' advances for construction	76,204	59,867
Unamortized investment tax credits	124,331	129,248
Accumulated deferred income taxes (Note 12)	445,530	275,247
Other	21,070	19,486
	667,135	483,848
Commitments and Contingencies (Notes 2, 8 and 10)		
Total Capital and Liabilities	$4,057,600	$3,759,583

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Public Service Company of Colorado and Subsidiaries — *Years ended December 31, 1993, 1992 & 1991*

		(Thousands of Dollars)	
	1993	1992	1991
Retained Earnings at Beginning of Year	**$247,725**	$238,715	$212,514
Net Income	**157,360**	136,623	149,693
	405,085	375,338	362,207
Dividends:			
On cumulative preferred stock:			
$100 par value:			
4.20% series	**420**	420	420
4¼% series	**744**	744	744
4½% 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	**1,620**	1,620	1,665
8.40% series	**2,012**	2,051	2,139
$25 par value:			
8.40% series	**2,940**	2,940	2,940
	12,028	12,067	12,200
On common stock:			
$2.00 per share in 1993, 1992 and 1991	**119,722**	115,546	111,292
	131,750	127,613	123,492
Retained Earnings at End of Year	**$273,335**	$247,725	$238,715

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Public Service Company of Colorado and Subsidiaries *Years ended December 31, 1993, 1992 & 1991*

	1993	1992	1991
		(Thousands of Dollars)	
Operating Activities:			
Net income	$ 157,360	$ 136,623	$ 149,693
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	143,940	134,335	118,943
Termination of Synhytech project	-	26,893	-
Loss on sale of real estate investments	-	11,370	-
Amortization of investment tax credits	(4,917)	(5,138)	(5,230)
Deferred income taxes	33,435	23,766	26,122
Allowance for equity funds used during construction	(8,119)	(7,378)	(4,763)
Change in accounts receivable	(3,813)	10,380	(17,024)
Change in inventories	(25,378)	6,024	(8,570)
Change in other current assets	(14,619)	(24,670)	21,811
Change in accounts payable	31,909	10,373	(5,948)
Change in other current liabilities	(5,439)	(16,101)	12,630
Change in deferred amounts	(17,483)	23,011	(121,665)
Change in other noncurrent liabilities	(14,759)	(57,207)	132,134
Other	7,762	521	2,134
Net Cash Provided by Operating Activities	279,879	272,802	300,267
Investing Activities:			
Construction expenditures	(293,515)	(261,666)	(260,704)
Colorado-Ute asset acquisition	-	(265,385)	-
Allowance for equity funds used during construction	8,119	7,378	4,763
Proceeds from (cost of) disposition of property, plant and equipment	43,120	(3,187)	5,893
Purchase of other investments	(5,660)	(6,348)	(11,396)
Sale of other investments	8,678	97,357	15,002
Net Cash Used in Investing Activities	(239,258)	(431,851)	(246,442)
Financing Activities:			
Proceeds from sale of common stock (Note 1)	47,894	48,914	39,305
Proceeds from sale of long-term notes and bonds	257,913	296,476	97,204
Redemption of long-term notes and bonds	(274,829)	(94,197)	(42,918)
Proceeds from short-term borrowings	1,047,749	831,290	690,645
Repayment of short-term borrowings	(1,021,500)	(781,304)	(703,838)
Redemption of preferred stock	(200)	(714)	(2,576)
Dividends on common stock	(118,732)	(114,454)	(110,306)
Dividends on preferred stock	(12,033)	(12,081)	(12,251)
Net Cash Provided by (Used in) Financing Activities	(73,738)	173,930	(44,735)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(33,117)	14,881	9,090
Cash and Temporary Cash Investments at Beginning of Year	51,155	36,274	27,184
Cash and Temporary Cash Investments at End of Year	$ 18,038	$ 51,155	$ 36,274

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

1. Summary of Significant Accounting Policies

Business and regulation

Public Service Company of Colorado (the Company) is an operating public utility engaged, together with its subsidiaries, principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transmission, distribution, sale and transportation of natural gas. The Company is subject to the jurisdiction of The Public Utilities Commission of the State of Colorado (CPUC) with respect to its retail electric and gas operations and the Federal Energy Regulatory Commission (FERC) with respect to its wholesale electric operations and accounting policies and practices. Cheyenne Light, Fuel and Power Company (Cheyenne) and WestGas InterState, Inc. (WGI) are subject to the jurisdictions of The Public Service Commission of Wyoming (WPSC) and the FERC, respectively.

The Company and its regulated subsidiaries prepare their financial statements in accordance with the provisions of Statement of Financial Accounting Standards No. 71–"Accounting for the Effects of Certain Types of Regulation" (SFAS 71). In general, SFAS 71 recognizes that accounting for rate regulated enterprises should reflect the relationship of costs and revenues introduced by rate regulation. As a result, a regulated utility may defer recognition of a cost (a regulatory asset) or recognize an obligation (a regulatory liability) if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in revenues. To the extent the Company concludes that collection of such revenues (or payment of liabilities) is no longer probable, through changes in regulation and/or the Company's competitive position, the associated regulatory asset or liability will be reversed with a charge or credit to income.

Accordingly, the Company and its regulated subsidiaries have deferred certain costs, which are being amortized over various periods, related to nuclear decommissioning, income taxes, employees' postretirement benefits other than pensions, demand side management and unamortized debt expense (see Notes 2, 5, 8, 10 and 12).

Consolidation

The Company follows the practice of consolidating the accounts of its significant subsidiaries. All intercompany items and transactions have been eliminated. Effective January 1, 1993, Western Gas Supply Company (WestGas) was merged into the Company and the three pre-existing WestGas subsidiaries, WGI, WestGas Gathering, Inc. (WGG) and WestGas TransColorado, Inc., became wholly-owned subsidiaries of the Company.

Revenue recognition

The Company and Cheyenne accrue for estimated unbilled revenues for services provided after the meters were last read on a cycle billing basis through the end of each year.

Statements of cash flows

For purposes of the consolidated statements of cash flows, the Company and its subsidiaries consider all temporary cash investments to be cash equivalents. These temporary cash investments are securities having original maturities of three months or less or having longer maturities but with put dates of three months or less.

Income taxes and interest (excluding amounts capitalized) paid:

		(Thousands of Dollars)	
	1993	1992	1991
Income taxes	**$ 49,196**	$ 38,624	$44,418
Interest	**$129,844**	$112,695	$96,010

Non-cash transactions:
Shares of common stock, (329,220 in 1993, 333,418 in 1992 and 242,674 in 1991), valued at the market price on date of issuance (approximately $9.4 million in 1993, $8.7 million in 1992 and $5.3 million in 1991), were issued to the Employees' Savings and Stock Ownership Plan of Public Service Company of Colorado and Participating Subsidiary Companies. The estimated issuance values were recognized in other operating expenses during the respective preceding years. These stock issuances were not cash transactions and are not reflected in the consolidated statements of cash flows.

Depreciation

The Company and its subsidiaries use straight-line depreciation for financial 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. Total depreciation expense approximated an annual rate of 3.0% on the average cost of depreciable properties for the years ended December 31, 1993, 1992 and 1991.

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 against accumulated depreciation.

Fuel Resources Development Co. (Fuelco) uses the unit-of-production depreciation method for producing oil and gas properties. For income tax purposes, the Company and its subsidiaries use accelerated depreciation and other elections provided by the tax laws.

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 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. The Company capitalizes AFDC as a part of the cost of utility plant. The following rates or ranges of AFDC rates were used for the years 1993, 1992 and 1991:

	1993	1992	1991
AFDC rates	**10.21%**	8.95%-10.21%	8.76%-10.21%

Income taxes
The Company and its subsidiaries file consolidated state and Federal income tax returns. Income taxes are allocated to the subsidiaries based on separate company computations of taxable income or loss.

Effective January 1, 1993, the Company and its subsidiaries adopted Statement of Financial Accounting Standards No. 109–"Accounting for Income Taxes" (SFAS 109). In accordance with SFAS 109, an increase in the net accumulated deferred income tax liability and a corresponding regulatory asset were recognized on the consolidated balance sheet to give effect to temporary differences for which deferred taxes were not previously required to be provided (see Note 12).

Effective December 1, 1993, pursuant to the CPUC rate case decision (see Note 8), the Company adopted full income tax normalization for rate regulatory purposes with a 13 year amortization of prior flow-through amounts. Prior to December 1, 1993, the Company and its regulated subsidiaries provided for deferred income taxes to the extent allowed by regulatory agencies, including deferred taxes arising from the use of accelerated depreciation, accelerated cost recovery, qualifying accelerated amortization and timing differences due to unbilled revenues which include deferred gas and electric costs. In addition, the Company provided for deferred taxes on book-tax timing differences arising from items associated with the Fort St. Vrain Generating Station (Fort St. Vrain) (see Note 2), from certain customer refunds and for all book-tax timing differences included in FERC jurisdictional rates.

The Company's non-regulated subsidiaries provide for deferred taxes arising from all book-tax timing differences.

Investment tax credits have been deferred and are being amortized to income over the productive lives of the related property.

Recoverable purchased gas and electric energy costs–net
The Company and Cheyenne (and WestGas prior to the merger effective January 1, 1993) recover certain purchased gas and electric energy costs, in excess of amounts recovered through base rates, from their retail customers through various gas and electric cost adjustment tariffs (see Note 8). These cost adjustment tariffs, which include a provision for the collection of deferred purchased gas and electric energy costs, are revised periodically as prescribed by the appropriate regulatory agencies. The deferred costs are the difference between actual costs incurred and the amounts currently recovered from customers. A substantial portion of this deferred amount represents the costs incurred to provide gas and electric energy which customers have used but for which they have not yet been billed.

Gas in underground storage
Gas in underground storage is accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of gas in underground storage at December 31, 1993, exceeded the LIFO cost by approximately $8.5 million.

Cash surrender value of life insurance policies
The following amounts related to corporate-owned life insurance contracts, with one major insurance company, are recorded as a component of Investments, at cost, on the consolidated balance sheets:

	(Thousands of Dollars) 1993	1992
Cash surrender value of contracts	**$228,195**	$192,855
Borrowings against contracts	**226,429**	190,784
Net investment in life insurance contracts	**$ 1,766**	$ 2,071

Reclassification
Certain items in the 1992 and 1991 consolidated financial statements have been reclassified to conform with the 1993 manner of presentation.

2. Fort St. Vrain Nuclear Generating Station

Investment in Fort St. Vrain
In 1989, the Company announced its decision to end nuclear operations at Fort St. Vrain. The decision was based on the financial impact of an anticipated lengthy outage necessary to repair the plant's steam generator system coupled with the plant's history of reduced levels of generation. The Company has completed defueling from the reactor to the Independent Spent Fuel Storage Installation (ISFSI) as discussed below in the section entitled "Defueling" and commenced the decommissioning process as described below in the section entitled "Decommissioning".

During 1986, the Company entered into a Stipulation and Settlement Agreement with the CPUC, the Colorado Office of Consumer Counsel (OCC) and the other parties involved in litigation and administrative proceedings related to Fort St. Vrain's history of limited operations. As a result, the Company's investment in Fort St. Vrain was removed from rate base and certain charges were recognized including the write-down of a substantial portion of such investment and the recognition of the then estimated future unrecoverable defueling and decommissioning expenses.

The recovery of the remaining investment in Fort St. Vrain (approximately $63.4 million at December 31, 1993), as well as the regulatory asset established to reflect the effect of previously recognized tax deductions associated with such investment for which no deferred taxes were required to be provided (approximately $12.4 million at December 31, 1993), is primarily dependent on the Company's ability to repower the facility. As part of the Integrated Resource Plan (IRP), the Company is continuing to pursue the repowering of Fort St. Vrain in a phased approach. The Company has filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the CPUC to repower Fort St. Vrain as a 471 Mw gas fired combined cycle steam plant consisting of two combustion turbines and two heat recovery steam generators. The completion of the first unit, a 130 Mw combustion turbine, is scheduled for 1996, which will be followed by a 102 Mw heat recovery steam generator in 1998

and a 130 Mw combustion turbine and a 109 Mw heat recovery steam generator in 1999. Total cost of the new facility (excluding the current investment) is estimated to be approximately $200 million (in 1993 dollars). A final decision from the CPUC is expected no later than July 1994. If it becomes probable that all or a portion of the Company's current investment and/or the related regulatory asset associated with deferred income taxes will not be recovered, the Company will recognize an expense equal to the unrecoverable amounts at the time such unrecoverable amounts can be reasonably estimated.

Decommissioning

On December 27, 1991, the CPUC approved a Supplemental Settlement Agreement (the "Agreement") to the 1986 Fort St. Vrain Stipulation and Settlement Agreement, allowing the Company to continue with the early dismantlement/decommissioning of Fort St. Vrain. Early dismantlement/decommissioning assumes that following the removal of the spent fuel segments from the reactor (defueling), the radioactive components of the reactor will be dismantled and removed over an approximate three year period. Effective July 1, 1993, pursuant to the Agreement, the Company began recovering from customers approximately $124.4 million, plus a 9% carrying cost over a twelve year period. This amount represented the inflation adjusted estimated remaining cost of the early dismantlement/decommissioning activities not previously recognized as expense. At December 31, 1993, approximately $118.4 million of such amount remains to be collected from customers and, therefore, is reflected as a regulatory asset on the consolidated balance sheets. The annual amount recovered from customers each year will be approximately $13.9 million.

On November 23, 1992, the Nuclear Regulatory Commission (NRC) approved the Company's early dismantlement/decommissioning plan. The Company has contracted with Westinghouse Electric Corporation and MK-Ferguson, a division of Morrison Knudsen Corporation, for the early dismantlement/decommissioning of Fort St. Vrain. Since defueling has been completed from the reactor to the ISFSI (discussed below) and the NRC decommissioning order has been received, the Company and the contractors have proceeded with decommissioning activities. At December 31, 1993, approximately 44% of the decommissioning process has been performed with final completion of such activities anticipated during 1995.

The decommissioning contract stipulates a fixed price, based on a defined work scope; however, such price has been and could be further modified due to changes in work scope or applicable regulations. While the Company has agreed to three substantive changes in work scope since the initiation of decommissioning activities, a revision in the defueling and decommissioning liability to date has not been required as the original estimate included a contingency provision. Such contingency provision, however, has been reduced as a result of the agreed upon work scope modifications.

The Company has been notified by the decommissioning contractors of several additional potential work scope changes. Final resolution of the potential work scope changes will require, among other things, further investigation of the radiation levels present in the reactor core. Such investigation is currently being conducted. At this time, the Company cannot predict the likelihood, timing of recognition, or the amount of additional costs, if any, that may result from such potential work scope changes.

Following is a reconciliation of the recorded defueling and decommissioning cost estimate from September 30, 1986, when the plant was removed from rate base, to December 31, 1993:

	(Thousands of Dollars)
Defueling and decommissioning liability–9/30/86	$ 95,404
Revision in estimate–9/30/88	63,764
Revision in estimate–3/31/91	13,099
Present value adjustments accrued through 9/30/91	36,428
CPUC approved additional cost recovery–12/31/91	124,444
Revision in estimate–12/31/92	(1,350)
	331,789
Defueling expenditures through 12/31/93	(147,115)
Decommissioning expenditures through 12/31/93	(91,567)
Defueling and decommissioning liability–12/31/93*	$ 93,107
*Maintaining and defueling the ISFSI	$ 10,578
Decommissioning	82,529
	$ 93,107

Because of the possibility of further changes in the decommissioning work scope, changes in applicable regulations and/or the uncertainties related to the final disposal of spent fuel, there can be no assurance that the actual cost of defueling and decommissioning will not exceed the estimated liability. The Company could be required to revise the estimated cost of defueling and decommissioning as a result of any such matters.

Defueling

In 1965, the Company, the Atomic Energy Commission (now the Department of Energy (DOE)) and General Dynamics entered into an agreement to construct Fort St. Vrain. The 1965 agreement, as amended and modified, requires the DOE to designate a facility for the temporary storage and reprocessing of Fort St. Vrain's first eight spent fuel segments and additional spent fuel segments at the DOE's discretion. Pursuant to the terms of an agreement dated April 1, 1980, among the Company, the DOE and General Dynamics, the DOE designated the Idaho National Engineering Laboratory (INEL) for receipt and temporary storage and reprocessing of the Fort St. Vrain first eight spent fuel segments. On June 24, 1983, the Company and the DOE entered into a contract for the disposal of spent nuclear fuel and/or high level radioactive waste from Fort St. Vrain be-

ginning with fuel segment 9, in the event the DOE does not accept segment 9 under the provisions of the 1965 agreement, as amended and modified. The Company intends to pursue with the DOE the storage/reprocessing of the equivalent spent fuel elements of segment 9 at the INEL in conjunction with the storage/reprocessing of the first eight segments.

In addition to its contractual obligations to provide for temporary storage and reprocessing of Fort St. Vrain spent fuel segments, the DOE is required by Federal statute to provide a repository for the permanent storage and disposal of spent nuclear fuel beginning in 1998. However, the DOE currently estimates that such a repository will not be available until 2010. Absent other arrangements with the DOE as discussed above, the equivalent spent fuel elements of segment 9 will be stored at the ISFSI. While the plant was operating and as part of routine refueling procedures, three spent fuel segments were transported to the INEL. After cessation of operations at Fort St. Vrain, defueling activities were initiated and authorization from the DOE to commence the shipment of the spent nuclear fuel to the INEL was received in February 1991.

Despite the Company's arrangements with the DOE, several parties contested the shipment of Fort St. Vrain spent nuclear fuel to the State of Idaho. As a result, several lawsuits were filed during 1991 by and among the Company, the DOE, the State of Idaho and the Shoshone-Bannock Indian Tribes, whose reservation is located near the INEL. While the Company was able to ship some fuel elements to the INEL following the initiation of litigation, no shipments have been made since October 1991. Initially, this was because of an injunction, which was subsequently set aside, that precluded the DOE from receiving spent fuel at the INEL. Most recently, the U.S. District Court for the District of Idaho ordered the DOE to prepare an Environmental Impact Statement (EIS) relative to, among other things, the receipt and storage of spent fuel at the INEL. Accordingly, the DOE will not accept any more shipments of spent fuel until the EIS is completed. The DOE has issued an implementation plan for the EIS which anticipates issuance of the final EIS by June 1995. In addition, the Company believes a facility readiness review may be required. Such review is a standard DOE procedure required to validate the readiness of equipment following a shut-down period. If such a review is required, it is uncertain whether the review will be conducted concurrently with or subsequent to the completion of the EIS. The Company currently anticipates that it will begin shipment of the spent fuel to the INEL in 1995 with expected completion in 1997.

The Company constructed the ISFSI for the interim storage of spent fuel segments 4-9 in order to safeguard against any potential future delays in the defueling process. Accordingly, on December 26, 1991, the Company began defueling the reactor to the ISFSI and completed such activities on June 10, 1992.

While the Company intends to pursue all available legal actions to enable it to ship the spent fuel to Idaho, the eventual outcome of this issue, and its timing, are uncertain. If, because the litigation discussed above is not resolved or because of other uncertainties, it becomes probable that storage of the spent fuel in the ISFSI will be required until 2020 (which the Company assumes is the earliest that a Federal repository could take such fuel), the Company would be required to recognize an additional incremental expense of approximately $17 million, determined on a present value basis. These expenditures have been escalated for inflation using an average rate of 3.2% and discounted to present value at a rate of 7.5%. The Company has assumed, consistent with the Nuclear Waste Policy Act, that costs associated with the shipment of the fuel from the ISFSI to the Federal repository in 2020 are to be the responsibility of the DOE and such costs are, therefore, excluded from this estimate. At this time, the Company cannot predict the likelihood, timing of recognition, or the amount of such additional costs to be recognized, if any.

Funding

Under NRC regulations, the Company is required to make filings with, and obtain the approval of, the NRC regarding certain aspects of the Company's decommissioning proposals, including funding. On January 27, 1992, the NRC accepted the Company's funding aspects of the decommissioning plan. The Company has also obtained an unsecured irrevocable letter of credit totaling $125 million that meets the NRC's stipulated funding guidelines including those proposed on August 21, 1991 that address decommissioning funding requirements for nuclear power reactors that have been prematurely shut down. In accordance with the NRC funding guidelines, the Company is allowed to reduce the balance of the letter of credit based upon milestone payments made under the fixed-price decommissioning contract. As a result of such payments, at January 27, 1994, the letter of credit had been reduced to $92 million.

The Company had set aside approximately $30 million in trust accounts for decommissioning the reactor. Since decommissioning activities have commenced, the Company completed withdrawing funds from the trust accounts during the second quarter of 1993. As previously discussed, on July 1, 1993, the Company commenced collection of the remaining decommissioning costs from customers.

In addition, the Company has established a separate decommissioning trust for the ISFSI which had funds of approximately $1.6 million at December 31, 1993. It is anticipated that this amount, together with the expected earnings on the funds, will be sufficient to decommission the ISFSI in 1997.

Costs for maintaining the ISFSI and removing fuel from the ISFSI, which the Company is not required to prefund, will be paid from a combination of operating funds of the Company and its subsidiaries and/or the issuance of securities.

Nuclear Insurance

The Price Anderson Act, as amended, limits the public liability of a licensee for a single nuclear incident at its nuclear power plant to the amount of financial protection available through liability insurance and deferred premium assessment charges, currently approximately $7.8 billion, which includes a 5% surcharge. Financial protection for this exposure is provided by private insurance and an indemnity agreement with the NRC. Since July 1, 1989, the Company has maintained approximately $200 million of private insurance, the amount required by the NRC. In the event of a nuclear incident involving a licensed commercial power plant in the United States that results in damages in excess of the private liability insurance, each reactor licensee, including the Company, is required to share in the liability up to the maximum amount through a deferred premium assessment. The maximum amount the Company would be required to pay in respect of each incident at a United States nuclear plant would be approximately $79.3 million (which includes a 5% surcharge), indexed every five years for inflation, provided that not more than $10 million would be payable per incident in any one year.

On February 25, 1993, the Company requested a revision to the Price Anderson indemnity agreement with the NRC to reduce the amount of private liability insurance from $200 million to $50 million and to delete any secondary responsibility to share in the liability for a nuclear incident at another power plant. This reduction in liability coverage would reflect the shutdown and defueled condition of the plant and the reduced risks of accidents resulting in radiological releases. The NRC is reviewing the Company's request.

In addition to the Company's liability insurance, Federal regulations require the Company to maintain $1.06 billion in nuclear property insurance. Effective February 1, 1991, however, the NRC granted the Company's exemption request to reduce the nuclear property insurance coverage from $1.06 billion to a minimum of $169 million. This lower limit would cover stabilization and decontamination expenses resulting from a worst case accident. The Company currently maintains $281 million in property insurance coverage. The additional insurance coverage above the $169 million is necessary to provide coverage for the estimated depreciated replacement value of the plant assets that will be used in the repowering of Fort St. Vrain.

3. Divestiture of Nonutility Assets

As part of the Company's strategy to focus its efforts on the core electric and gas businesses, the Company has divested certain nonutility investments.

Fuel Resources Development Co.

Investment in Synhytech Project

In December 1992, the Company terminated its involvement in Fuelco's Synhytech fuel conversion technology project. As a result, Fuelco recognized an expense of approximately $26.9 million ($16.8 million after-tax) associated with writing-off its entire investment in the Synhytech plant and recognizing certain additional costs which were incurred in connection with the termination of this project.

On May 20, 1993, the Synhytech assets were transferred to Rentech, Inc. in exchange for resolution of all claims between the Company and Rentech, Inc. that had been or could have been asserted with respect to the Synhytech plant and related technology. Rentech, Inc. had been involved with various aspects of the Synhytech project since the project's inception. Fuelco's subsidiary, Synhytech, Inc., was dissolved, effective December 31, 1993.

Investment in Templeton Gap

In June 1993, the Company decided to terminate its involvement in Fuelco's Templeton Gap methane recycling facility. The facility recycles landfill gas into usable natural gas that is sold to the City of Colorado Springs. In connection with this decision, Fuelco recognized an expense of approximately $4.4 million ($3.1 million after-tax) associated with writing-off its entire investment in the facility and recognizing certain additional termination costs. The Company is pursuing the sale of this facility.

Investment in Oil and Gas Production Properties

On June 22, 1993, the Company's Board of Directors approved pursuing the divestiture of Fuelco's remaining oil and gas related production properties. While the properties were originally marketed as a total package, disaggregation into four major asset groups occurred. As of February 1, 1994, the sale of three of the four asset groups was completed. A purchase and sale contract for the remaining asset group, the San Juan Coal Bed Methane properties, is being negotiated with closing anticipated no later than the end of the first quarter of 1994. Subsequent to the final asset disposition, the Company will bring Fuelco's operations to a close through realization of the remaining other assets and the funding of any remaining other liabilities.

In December 1993, the Company recorded the effects of the disposition of all properties, including the 1994 anticipated sale, and additional costs expected to be incurred through the close of operations. The effect of these transactions had no material impact on the Company's 1993 results of operations or financial position.

Bannock Center Corporation (BCC)

In December 1992, BCC sold substantially all of its real estate properties located near downtown Denver for $6 million, resulting in a loss of approximately $11.4 million ($8.4 million after-tax). Effective November 30, 1993, BCC was dissolved.

4. Capital Stock

Common Stock

	1993		1992	
	Shares	**Amount**	Shares	Amount
		(Thousands of Dollars)		(Thousands of Dollars)
Common stock, $5 par value:				
Authorized	**140,000,000**		140,000,000	
Issued and outstanding	**60,457,375**	**$302,287**	58,476,805	$292,384
Premium on common stock		**608,561**		560,938
		$910,848		$853,322

Changes in common stock and premium on common stock for the three years ended December 31, 1993 are as follows:

	Average Price Per Share	Common Stock (Thousands of Dollars)	Premium on Common Stock (Thousands of Dollars)
Balance, January 1, 1991		$271,601	$479,548
242,674 shares issued under the Employees' Savings Plan	$21.69	1,214	4,050
1,730,603 shares issued under the Dividend Reinvestment Plan	$22.71	8,653	30,652
Balance, December 31, 1991		281,468	514,250
333,418 shares issued under the Employees' Savings Plan	$26.06	1,667	7,022
1,849,862 shares issued under the Dividend Reinvestment Plan	$26.44	9,249	39,666
Balance, December 31, 1992		292,384	560,938
329,220 shares issued under the Employees' Savings Plan	$28.44	1,646	7,716
1,651,350 shares issued under the Dividend Reinvestment Plan	$29.17	8,257	39,907
Balance, December 31, 1993		$302,287	$608,561

On December 7, 1992, the Company filed a registration statement with the Securities and Exchange Commission (SEC) relating to the registration of 1,000,000 common stock shares, $5 par value, and 1,000,000 common share purchase rights. These shares and rights are associated with the Company's Omnibus Incentive Plan discussed in Note 10.

During 1991, the Company's Board of Directors declared a dividend of one common share purchase right ("right") on each outstanding share of the Company's common stock. All future common shares issued will contain this right. Each right stipulates an initial purchase price of $55 per share and also prescribes a means whereby the resulting effect is such that, under the circumstances described below, shareholders would be entitled to purchase additional shares of common stock at 50% of the prevailing market price at the time of exercise. The rights are not currently exercisable, but would become exercisable if certain events occurred related to a person or group acquiring or attempting to acquire 20% or more of the outstanding shares of common stock of the Company.

In the event a takeover results in the Company being merged into an acquiror, the unexercised rights could be used to purchase shares in the acquiror at 50% of market price. Subject to certain conditions, if a person or group acquires 20% but no more than 50% of the Company's common stock, the Company's Board of Directors may exchange each right held by shareholders other than the acquiring person or group for one share of common stock (or its equivalent).

If a person or group successfully acquires 80% of the Company's common stock for cash, after tendering for all of the common stock, and satisfies certain other conditions, the rights would not operate. The rights expire on March 22, 2001; however, each right may be redeemed by the Board of Directors for one cent at any time prior to the acquisition of 20% of the common stock by a potential acquiror.

Preferred Stock

	1993		1992	
	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[illegible]% series (includes $7,500 premium)	**175,000**	**17,508**	175,000	17,508
4[illegible]% 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	$105,008
Subject to mandatory redemption:				
7.50% series	**216,000**	**$ 21,600**	216,000	$ 21,600
8.40% series	**238,545**	**23,854**	240,545	24,054
	454,545	**45,454**	456,545	45,654
Less: Preferred stock subject to mandatory redemption within one year	**(25,760)**	**(2,576)**	(25,760)	(2,576)
Total	**428,785**	**$ 42,878**	430,785	$ 43,078
Cumulative preferred stock, $25 par value:				
Authorized	**4,000,000**		4,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
8.40% series	**1,400,000**	**$ 35,000**	1,400,000	$ 35,000

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:

Cumulative preferred stock, not subject to mandatory redemption:
$100 par value, all series: $101 per share.

$25 par value, 8.40% series: $25.25 per share.

Cumulative preferred stock, subject to mandatory redemption:
7.50% series: $102.50 per share on or prior to August 31, 1994, reducing each year thereafter by $0.25 per share until August 31, 2003, after which the redemption price is $100 per share; 8.40% series: $102.75 per share on or prior to July 31, 1994, and reducing each year thereafter by $0.25 per share until July 31, 2004, after which the redemption price is $100 per share.

In 1994 and in each year thereafter, the Company must offer to repurchase 12,000 shares of the 7.50% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase, and 13,760 shares of the 8.40% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase. Consequently, this preferred stock to be redeemed is classified as preferred stock subject to mandatory redemption within one year in the December 31, 1993 consolidated balance sheet. In 1993, the Company repurchased 2,000 shares of the 8.40% cumulative preferred series subject to mandatory redemption. In 1992 the Company repurchased 7,135 shares of the 8.40% cumulative preferred series subject to mandatory redemption. In 1991, the Company repurchased 13,760 shares of the 8.40% cumulative preferred series and 12,000 shares of the 7.50% cumulative preferred series subject to mandatory redemptions. No other changes in preferred stock occurred in the three years ended December 31, 1993.

5. Long-Term Debt

	(Thousands of Dollars) 1993	1992
Public Service Company of Colorado:		
First Collateral Trust Bonds:		
6⅜% series, due November 1, 2005	$134,500	$ –
First Mortgage Bonds:		
4⅜% series, due June 1, 1994	35,000	35,000
5⅝% series, due May 1, 1996	35,000	35,000
5⅞% series, due July 1, 1997	35,000	35,000
6⅜% series, due July 1, 1998	25,000	25,000
8⅜% series, due September 1, 2000	–	35,000
7¼% series, due February 1, 2001	40,000	40,000
7½% series, due August 1, 2002	50,000	50,000
7⅝% series, due June 1, 2003	50,000	50,000
8⅛% series, due March 1, 2004	100,000	100,000
9⅜% series, due October 1, 2005	–	49,500
8¾% series, due November 1, 2007	49,500	50,000
9¼% series, due October 1, 2008	–	50,000
9⅛% series, due July 1, 2020	75,000	75,000
8⅞% series, due March 1, 2022	150,000	150,000
Pollution Control Series A,		
5⅞%, due March 1, 2004	24,000	24,000
Pollution Control Series B:		
7⅛%, due December 1, 1995	–	2,500
8%, due December 1, 2004	–	35,000
Pollution Control Series C:		
7⅛%, due October 1, 2004	–	15,000
7¼%, due October 1, 2005	–	1,960
7¼%, due October 1, 2006	–	2,105
7⅜%, due October 1, 2007	–	2,260
7½%, due October 1, 2008	–	2,425
7⅝%, due October 1, 2009	–	26,250
Pollution Control Series E,		
9⅛%, due May 1, 2013	–	42,000
Pollution Control Series F,		
7⅜%, due November 1, 2009	27,250	27,250
Pollution Control Series G,		
5⅝%, due April 1, 2008	18,000	–
5⅞%, due April 1, 2014	61,500	–
Pollution Control Series H,		
5⅛%, due June 1, 2012	50,000	–
Secured Medium-Term Notes, Series A:		
8.38%, retired January 12, 1994	10,000	10,000
8.375%, retired January 17, 1994	10,000	10,000
8.55%, due January 11, 1995	20,000	20,000
8.82%, due January 15, 1996	15,000	15,000
8.90%, due August 1, 1997	5,000	5,000
8.90%, due August 15, 1997	5,000	5,000
6.66%, due October 30, 1997	20,000	20,000
6.66%, due October 30, 1997	5,000	5,000
9%, due April 1, 1998	5,000	5,000
9.08%, due March 15, 1999	10,000	10,000
8.90%, due August 10, 1999	5,000	5,000
7.23%, due November 1, 1999	10,000	10,000
9.25%, due March 27, 2001	6,500	6,500

	(Thousands of Dollars) 1993	1992
Public Service Company of Colorado: *(continued)*		
First Mortgage Bonds: *(continued)*		
Secured Medium-Term Notes, Series A: *(continued)*		
7.28%, due October 22, 2002	**$ 5,000**	$ 5,000
7.28%, due October 22, 2002	**5,000**	5,000
7.65%, due October 30, 2002	**5,000**	5,000
Unsecured promissory notes:		
7⅜%, due December 1, 1997	**20,000**	20,000
10.35%, due in installments through December 1, 1999	**1,333**	2,667
11.60%, due May 1, 2015	**5,000**	5,000
12.875%, due May 1, 2025	**10,000**	10,000
Unamortized premium	**157**	485
Unamortized discount	**(3,686)**	(2,136)
Capital lease obligations, 8.40%-14.65%, due in installments through August 31, 1998	**1,112**	1,649
	1,135,166	1,139,415
Cheyenne Light, Fuel and Power Company:		
First Mortgage Bonds:		
7¼% series, due April 1, 2003	**4,000**	4,000
Industrial Development Revenue Bonds, 7.25%, due September 1, 2021	**7,000**	7,000
10.70 % unsecured notes, due September 1, 1995	**8,000**	8,000
1480 Welton, Inc.:		
12.50% secured promissory note, due in installments through March 1, 1998	**6,766**	7,903
13.25% secured promissory note, due in installments through October 1, 2016	**32,320**	32,527
Fuel Resources Development Co.:		
Capital lease obligations, 7.09% due in installments through May 1, 1996	**303**	781
Natural Fuels Corporation:		
12.25% secured note, due in installments through May 23, 1994	**2**	6
Capital lease obligations, 8¾% due in installments through August 31, 1996	**111**	147
	1,193,668	1,199,779
Less: Maturities due within one year	**58,324**	2,820
	$1,135,344	$1,196,959

In 1990, the Company filed a registration statement with the SEC relating to a $500 million principal amount of First Mortgage Bonds of which $200 million was subsequently designated for offering pursuant to a secured medium-term note program. At December 31, 1993, $50 million of First Mortgage Bonds and $58.5 million of medium-term notes remain available for issuance.

On October 7, 1992, the CPUC approved the refinancing of certain outstanding bonds with new issue, lower cost debt securities at the Company's discretion prior to December 31, 1995. During 1993, the Company refinanced $129.5 million of its Pollution Control Bonds.

In 1993, the Company filed two registration statements with the SEC relating to an aggregate of $457.2 million principal amount of First Collateral Trust Bonds for the refinancing of First Mortgage Bonds. During 1993, $134.5 million of the First Collateral Trust Bonds were issued. In January 1994, the Company issued $212.7 million aggregate principal amount of 7-year and 30-year bonds at interest rates of 6% and 7.25%, respectively. The Company will continue from time to time to offer such secured medium-term notes and bonds based on market conditions and other factors.

In January 1994, Cheyenne refinanced its 10.7% unsecured note with 30-year First Mortgage Bonds, 7⅝% series.

At December 31, 1993, PS Colorado Credit Corporation (PSCCC) had in place a program to sell its private medium-term notes, with maturities from nine months to ten years, up to an amount of $100 million outstanding at any one time.

There were no amounts outstanding under this program at December 31, 1993 or 1992.

Substantially all properties of the Company and its subsidiaries, other than expressly excepted property, are subject to the liens securing the Company's First Mortgage Bonds and First Collateral Trust Bonds or the mortgage bonds and notes of subsidiaries. Additionally, there is a second lien on the electric property securing the Company's First Collateral Trust Bonds. The Company's First Collateral Trust Bonds are additionally secured by an equal amount of First Mortgage Bonds which bear no interest.

The aggregate annual maturities and sinking fund requirements during the five years subsequent to December 31, 1993 are (in thousands of dollars):

Year	Maturities	Sinking Fund Requirements	Total
1994	$58,324	$3,410	$61,734
1995	30,667	3,410	34,077
1996	51,310	3,060	54,370
1997	91,205	2,710	93,915
1998	29,928	1,060	30,988

The Company expects to satisfy its sinking fund obligations through the application of property additions, and Cheyenne expects to satisfy $60,000 of its sinking fund obligations annually through the application of property additions.

6. Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended December 31, 1993 and 1992 is as follows:

	1993	1992 (Thousands of Dollars)
Notes payable to banks (weighted average interest rates of 3.69% at December 31, 1993 and 4.05% at December 31, 1992)	**$ 46,100**	$ 95,800
Commercial paper (weighted average interest rates of 3.58% at December 31, 1993 and 4.09% at December 31, 1992)	**230,775**	154,826
	$ 276,875	$ 250,626
Maximum amount outstanding at any month-end during the period	**$ 276,875**	$ 259,811
Weighted average amount (based on the daily outstanding balance) outstanding for the period (weighted average interest rates of 3.325% for the year ended December 31, 1993 and 4.24% for the year ended December 31, 1992)	**$ 237,526**	$ 231,770

7. Bank Lines of Credit and Compensating Bank Balances

Arrangements by the Company and its subsidiaries for committed lines of credit are maintained entirely by fee payments in lieu of compensating balances. Arrangements for uncommitted lines of credit have no fee or compensating balance requirements.

On November 22, 1993, the Company, PSCCC, and certain subsidiaries extended a credit facility with several banks providing $300 million in committed bank lines of credit. The credit facility, which is used primarily to support the issuance of commercial paper by the Company and PSCCC, alternatively provides for direct borrowings thereunder. Under the current extension, Cheyenne, 1480 Welton, Inc., Fuelco, PSR Investments, Inc., and WGG were provided access to the credit facility under a $125 million aggregate sub-limit with direct borrowings guaranteed by the Company.

At December 31, 1993, there were $300 million in available commitments of which $23.1 million remained unused. Generally, the banks as participants in the facility would have no obligation to continue their commitments if there has been a material adverse change in the consolidated financial condition, operations, business or otherwise, that would prevent the Company and its subsidiaries from performing their obligations under the facility. The facility expires April 1, 1994.

The Company had no individual arrangements for uncommitted bank lines of credit at December 31, 1993. The Company and its subsidiaries generally may borrow under uncommitted preapproved lines of credit upon request; however, the banks have no firm commitment to make such loans. On January 3, 1994, the Company established uncommitted lines of credit totaling $25 million, which expire on December 31, 1994.

8. Commitments and Contingencies

Regulatory Matters

1993 Rate Case

On January 20, 1993, the Company filed a general rate case with the CPUC. In its filing, the Company requested increases in electric, gas and steam rates designed to produce an increase in total annual base rate revenues from the level

of such revenues then authorized and in effect (after giving effect to the $3 million per month reduction discussed below under "Prior Rate Settlements") of $81.6 million, or 4.7%, on the basis of a rate of return on regulated rate base of 10.5%, including a rate of return on regulated common equity of 13%. The Company requested, among other principles, the use of a fully forecasted test year ended June 30, 1994 in establishing revenue requirements and the full normalization method of accounting for income taxes.

On November 26, 1993, the CPUC issued its final written decision which reduced the authorized level of the Company's total annual base rate revenues (after giving effect to the reductions under prior rate settlements) by approximately $5.2 million on the basis of a rate of return on regulated rate base of 9.4%, including a rate of return on regulated common equity of 11%. The new rates became effective December 1, 1993. Proceedings will be held in 1994 to determine cost allocation issues and the specific rate changes for the various customer classes.

The CPUC rejected the Company's proposed use of a fully forecasted test year in the establishment of revenue requirements in favor of an historical test year ended September 30, 1992. In addition, as part of the final decision, the following significant issues were addressed:

- the adoption of full income tax normalization with a 13 year amortization of prior flow-through amounts currently reflected as a regulatory asset on the balance sheet,
- continued inclusion in rate base of the Pawnee Steam Electric Generating Station, Unit 2 (proposed) engineering costs ($18 million) and the investment in Southeast Water Rights ($28 million), but with an allowed rate of return on such assets based on the Company's weighted cost of debt and preferred stock, and
- retention of the Company's Electric Cost Adjustment (ECA), allowing the continued pass-through of electric energy costs to customers, and the opening of new dockets in the future to reevaluate the ECA and the Gas Cost Adjustment (GCA) mechanisms.

As part of its order, the CPUC advised the Company of its concerns regarding the Company's need to more fully document the prudence of expenditures incurred for its new computerized Customer Information System. The system, which cost approximately $65 million, became operational in August 1993. As a result, the Company will address this issue at the time it seeks rate recovery for these costs as it will be the Company's burden to establish that such costs were prudently incurred.

On December 27, 1993, the OCC filed in the District Court in and for the City and County of Denver (Denver District Court) an appeal of the CPUC decision. The OCC has claimed that certain of the CPUC's decisions, which are primarily income tax related issues, were not supported by substantial evidence. The Company will participate in the appeal. The Company believes that the resolution of this appeal will not have a material effect on its financial position or results of operations.

Prior Rate Settlements

On January 31, 1991, the Company filed a rate case with the CPUC requesting an increase in revenue levels, among other things. During June 1991, the Company, the OCC and other parties signed two Settlement Agreements and filed a joint motion to dismiss the Company's rate case. The terms of the Settlement Agreements and the dismissal of the rate case were approved by the CPUC on July 17, 1991. One of these Settlement Agreements, addressing revenue requirements, provided, among other things: (1) for a $22 million refund to electric customers in August 1991; (2) that the Company would file a rate case on November 2, 1992 and it would not seek an increase in base rates to be effective prior to July 1, 1993; and (3) for a reduction in electric rates of 3.38%, or approximately $3 million per month, for the period beginning January 1, 1992 and ending on the effective date of new rates.

Other Regulatory Matters

Demand Side Management (DSM)

Over the past few years, the Company has developed DSM programs, including incentive and recovery mechanisms. The programs, developed under a collaborative process, among the Company, public interest groups, consumers and industry, were proposed to the CPUC on February 16, 1993 and approved on May 5, 1993 with a schedule to be implemented over a three-year period. Effective July 1, 1993, the Company placed into effect a Demand Side Management Cost Adjustment (DSMCA) clause which permits it to recover non-labor incremental expenses, capital expenditures with carrying costs and certain incentives associated with the approved DSM programs. Under a separate CPUC order issued in December 1992, the Company is implementing a Low-Income Energy Assistance Program. The costs of this energy conservation and weatherization program for low-income customers will be recovered through the DSMCA. The total capitalized/deferred DSM costs were $10.4 million and $3.6 million at December 31, 1993 and 1992, respectively.

Incentive Regulation

The CPUC has opened a separate docket to investigate issues relating to the adoption and implementation of incentive regulation, which may include decoupling, for the Company's earnings, and additional DSM incentives. On February 10, 1994, the parties to this docket filed a settlement with the CPUC, which is intended to settle all issues in this docket. The hearing on such settlement was held before the CPUC on February 14, 1994, and the CPUC is expected to issue its decision on the acceptability of the settlement by mid-March 1994. The settlement provides for a continuation of DSM incentives for the Company's pursuit of DSM resources through 1998. From the Company's perspective, this settlement is intended to keep the Company whole with respect to revenues lost as a result of the implementation of DSM programs and also provides a modest incentive

for the encouragement of the Company's continued pursuit of DSM resources.

Integrated Resource Planning

In December 1992, the CPUC issued the Electric Integrated Resource Planning Rules establishing specific rules for the state's utilities to follow in preparing electric load forecasts and in securing broad public participation for assessing both supply- and demand-side options. On October 1, 1993, the Company filed its plan with the CPUC, which describes the mix of resources to be utilized and/or acquired by the Company over the next three years, including the repowering of Fort St. Vrain as a gas fired combined cycle steam plant. In addition, certain DSM measures have been identified to reduce the amount of additional capacity required to be supplied by the Company in the future. The Company's IRP is scheduled to be heard before the CPUC in April 1994 and a decision is anticipated by the end of May 1994.

GCA

On September 30, 1993, the Company filed an application with the CPUC requesting a $58 million revision in its GCA to cover the increased cost of natural gas purchased from suppliers over the next twelve months. In general, the higher costs are related to nationwide industry and marketplace adjustments to a new, deregulated gas industry and the higher price of gas at the wellhead. More specifically, the increase is related to: 1) rate increases by the Company's major gas supplier effective October 1, 1993, 2) new costs from the restructuring of services on interstate pipelines in response to the implementation of FERC Order Nos. 636-A and 636-B (FERC Order 636), and 3) an increase in gas commodity prices as the gas surplus that resulted in lower gas prices in the mid-1980's and early 1990's has diminished. The application was granted by the CPUC in an order issued on October 28, 1993. Beginning in 1994, the CPUC will conduct an annual review of the Company's GCA adjustments for the purpose of reviewing the justness and reasonableness of these adjustments.

ECA and Qualifying Facilities Capacity Cost Adjustment (QFCCA)

The Company's ECA mechanism has been revised and a new QFCCA mechanism was implemented on December 1, 1993, along with the base rate changes resulting from the rate case. Under the new ECA, fuel used for generation and purchased energy costs from utilities, Qualifying Facilities (QF's) and Independent Power Production Facilities (IPPF's) (excluding all purchased capacity costs) to serve retail customers, are recoverable. Purchased capacity costs are recovered as a component of base rates, except as described below. The ECA rate is revised annually on October 1. Recovered energy costs are compared with actual costs on a monthly basis and differences, including interest, are deferred. Under the new QFCCA, all purchased capacity costs from new QF projects, incurred subsequent to December 1, 1993, are recoverable similar to the ECA. These capacity costs are not reflected in the Company's base rates. While the CPUC approved the QFCCA, recovery of such costs may be subject to an earnings test, which has not yet been defined by the CPUC.

Environmental Issues

Environmental Site Cleanup

Under the Comprehensive Environmental Response, Compensation and Liability Act, the Environmental Protection Agency (EPA) has identified, and a Phase II environmental assessment has revealed, low level, widespread contamination from hazardous substances at the Barter Metals Company properties located in central Denver. For an estimated 30 years, the Company sold scrap metal and electrical equipment to Barter for reprocessing. The Company, which is one of several Potentially Responsible Parties (PRPs), is involved in the cleanup of this site which began in November 1992 and is expected to be completed during 1994. The total project cost is currently estimated to be approximately $6.0 million, of which $4.0 million has been incurred at December 31, 1993. The Company believes it is probable that a significant portion of these cleanup costs will be recovered through claims made against the Company's insurance companies. Lawsuits against these insurance companies have been filed in the Denver District Court. To the extent such costs are not recovered by insurance or from other PRPs, the Company intends to pursue recovery of those costs through the regulatory process.

Extensive Polychlorinated Biphenyl (PCB) presence has been identified in the basement of the Denver Gas and Electric Building, a historic office building located in downtown Denver. The PCB presence possibly occurred in the early 1970's and mid-1980's during routine transformer maintenance activities. The presence of PCB's may also have been caused or contributed to by the operations or activities of the building owners or service providers to the Denver Gas and Electric Building. The Company was negotiating the future cleanup with the current owners; however, on October 5, 1993 the owners filed a civil action against the Company in Denver District Court. The action alleges that the Company was responsible for the PCB releases and additionally claims other damages in unspecified amounts. Preliminary estimates of cleanup costs are approximately $4-$5 million. A jury trial has been set for August 15, 1994. The Company believes that it is probable that it will recover all costs incurred through insurance claims and/or the regulatory process.

The Company is pursuing reoccupation of its former Headquarters Office Building, however, the facility contains asbestos. As a result, asbestos abatement/removal at the site has been initiated. The estimated cost of the cleanup is approximately $9.0 million of which $0.3 million has been incurred at December 31, 1993. The abatement/removal is expected to be completed during 1994. The Company has recorded a liability and a related asset for the total estimated cost and intends to pursue recovery of these costs through the regulatory process.

The proposed Elitch Gardens Amusement Park site near downtown Denver has revealed low level, widespread contamination. The Company had used the site in the past as a manufactured gas plant site and is one of three PRPs. An agreement has been signed by Trillium Corporation, a PRP, Elitch Gardens Co. and the Company, releasing the Company from responsibility for the first $2 million of cleanup costs. Any costs exceeding that amount will be the responsibility of the Company; however, the Company could then pursue recovery of the incurred costs from Burlington Northern Railroad, the third PRP, and/or through insurance claims. The Company believes that the total cleanup costs will not exceed $2 million.

In addition to these sites, the Company has identified several sites where cleanup of hazardous substances may be required. While potential liability and settlement costs are still under investigation and negotiation, the Company believes that the resolution of these matters will not have a material effect on its financial position or results of operations. The Company fully intends to pursue the recovery of all significant costs incurred for such projects through insurance claims and/or the rate regulatory process. To the extent any costs are not recovered through the options listed above, the Company would be required to recognize an expense for such unrecoverable amounts.

Other Environmental Matters

On November 15, 1990, President George Bush signed into law the Federal Clean Air Act Amendments of 1990 (Amendments). The Amendments require coal burning power plants to reduce Sulfur Dioxide (SO_2) and Nitrogen Oxide (NOx) emissions to specified levels. The Company is currently meeting the emission standards placed on SO_2 through the use of low sulfur coal and the operation of pollution control equipment on certain generation facilities. The Company will be required to modify certain boilers by the year 2000 to reduce NOx emissions at an estimated total future cost of approximately $25.8 million. The Company is studying its options to reduce SO_2 emissions and currently does not anticipate that these regulations will significantly impact its operations.

On August 18, 1993, a conservation organization filed a complaint in U.S. District Court for the District of Colorado, pursuant to Section 304 of the Federal Clean Air Act, against the Company and the other joint owners of the Hayden Steam Electric Generating Station (Hayden). The plaintiff alleges that, on certain occasions, the station exceeded opacity limitations during the past several years. The complaint seeks, among other things, civil monetary penalties. At this time the Company is not able to estimate the amount, if any, of its potential liability or whether additional particulate control equipment will be required. The suit is in the early discovery stages and a trial date has been set for August 1995.

The Metro Denver Brown Cloud II study, designed to investigate the formation of secondary particulates, was completed during the third quarter of 1993. The results of the study have not altered the Company's current programs to reduce SO_2 and NOx emissions. The Company continues to research and implement various SO_2 and NOx emissions reduction projects, including two Clean Coal Technology III (CCT3) projects. Research and implementation continues on the two CCT3 projects, which involve the Arapahoe Steam Electric Generating Station Unit 4 and the Cherokee Steam Electric Generating Station Unit 3. Testing is expected to be completed at both units by mid-1994.

The Company believes that, consistent with historical regulatory treatment, any costs to comply with pollution control regulations would be recovered from its customers. However, no assurance can be given that this practice will continue in the future.

Purchase requirements

Coal

At December 31, 1993, the Company had in place long-term contracts for the purchase of coal for existing power plants through 2017. The minimum remaining quantities to be purchased under these contracts total 99 million tons. The coal purchase prices are subject to periodic adjustment for inflation and market conditions. Total estimated obligations, based on current prices, were approximately $1 billion at December 31, 1993.

Coal transportation

The Company has entered into long-term contracts for the transportation of coal by railroad in Company-owned or leased railcars to existing power plants. These agreements, expiring in 1997, provide for a minimum remaining transport quantity of 20 million tons. Coal transport contract prices are negotiated based on market conditions and are adjusted periodically for inflation and operating factors. Total estimated obligations, based on current prices, were approximately $105 million at December 31, 1993.

Natural gas purchases and transportation

The Company and Cheyenne have entered into long-term contracts for the purchase, firm transportation and storage of natural gas which expire on various dates through the year 1998. In compliance with the rules established by FERC Order 636, the Company has renegotiated the contracts with its two primary gas pipeline suppliers and has committed to continue purchasing gas for the next three years. The Company will not incur any gas supply realignment costs otherwise applicable under FERC Order 636. At December 31, 1993, the Company and Cheyenne have minimum obligations under such contracts of $279 million in 1994, declining thereafter for a total estimated commitment of $685 million.

Purchased power

The Company and Cheyenne have entered into agreements with utilities and qualifying facilities for purchased power to meet system load and energy requirements, to replace generation from Company-owned units under maintenance and

outages, and to meet the Company's operating reserve obligation to the Inland Power Pool.

The Company has various pay-for-performance contracts with QF's having expiration dates through the year 2025. In general, these contracts provide for capacity payments, subject to the QF's meeting certain contract obligations, and energy payments based on actual power taken under the contracts. The energy and capacity costs are recovered through the ECA and QFCCA mechanisms. Additionally, the Company and Cheyenne have long-term purchased power contracts with various regional utilities expiring through 2022. In general, these contracts provide for capacity and energy payments which approximate the cost of the sellers. These costs have historically been recoverable through ECA mechanisms; however, effective December 1, 1993, the Company's capacity costs were reflected in base rates. Total capacity and energy payments associated with such contracts were $366 million, $332 million and $254 million in 1993, 1992 and 1991, respectively.

At December 31, 1993, the estimated future payments for capacity that the Company and Cheyenne are obligated to purchase, subject to availability, are as follows:

(Thousands of Dollars)

Year	QF's	Regional Utilities	Total
Ending December 31,			
1994	$ 111,569	$ 175,543	$ 287,112
1995	153,809	176,233	330,042
1996	157,637	182,442	340,079
1997	157,637	184,141	341,778
1998	157,353	183,048	340,401
1999 and thereafter	1,667,155	2,411,244	4,078,399
Total	$2,405,160	$3,312,651	$5,717,811

Historically, all minimum coal, coal transportation, natural gas, and purchased power requirements have been met.

Other purchases

Commitments made for the purchase of materials, plant and equipment and other various items aggregated approximately $428 million at December 31, 1993.

Employee Litigation

Several employee lawsuits have been filed against the Company involving alleged sexual/age discrimination. In addition, certain em[illegible]yees terminated as part of the Company's 1991/[illegible]nizational analysis have asserted breach of contrac[illegible]missory estoppel with respect to job security and breach of the covenant of good faith and fair dealing. The Company is actively contesting the lawsuits and believes the ultimate outcome will not have a material impact on the Company's results of operations or financial position.

Fort St. Vrain

See Note 2 for certain co[illegible]s relating to Fort St. Vrain.

Leasing Program

The Company has in place a leasing program which includes a provision whereby the Company indemnifies the lessor for all liabilities which might arise from the acquisition, use, or disposition of the leased property. See Note 15 for additional discussion of leasing information.

9. Jointly-Owned Electric Utility Plants

On April 15, 1992, the Company, Tri-State Generation and Transmission Association (Tri-State), PacifiCorp, and Intermountain Rural Electric Association completed the acquisition of assets of Colorado-Ute Electric Association Inc., (Colorado-Ute) pursuant to the Joint Plan of Reorganization as filed and approved in the Chapter 11 reorganization of Colorado-Ute in the U.S. Bankruptcy Court. The total acquisition cost to the Company was approximately $265 million.

The generating assets of Colorado-Ute, primarily the Craig Steam Electric Generating Station (Craig) and Hayden coal-fired plants in northwestern Colorado, were divided among the Company, Tri-State and PacifiCorp. The Company acquired approximately 331 Mw of net dependable generating capability. Other property acquired included transmission and distribution lines and facilities.

As a result of the acquisition of Colorado-Ute assets, the Company is responsible for its proportionate share of operating expenses (reflected in the 1993 and 1992 consolidated statements of income) and construction expenditures. Following is the Company's investment in jointly-owned plants and its ownership percentages as of December 31, 1993:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
	(Thousands of Dollars)			
Hayden Uni[illegible]	$ 34,507	$ 28,471	$1,177	75.50
Hayden Un[illegible]	57,208	27,826	210	37.40
Hayden Co[illegible]acilities	1,599	1,212	1,756	53.10
Craig Units 1[illegible]	56,718	19,470	245	9.72
Craig Common Facilities Units 1 & 2	7,398	2,562	570	9.72
Craig Common Facilities Units 1, 2 & 3	8,125	2,721	561	6.47
Transmission Facilities, Including Substations	70,407	18,416	–	42.0-73.0
	$235,962	$100,678	$4,519	

10. Employee Benefits

Pensions

The Company and its subsidiaries (excluding Natural Fuels) maintain a noncontributory defined benefit pension plan covering substantially all employees. During 1993, the Board of Directors of the Company approved amendments that: 1) eliminated the minimum age of 21 for receiving credited service, 2) provided for an automatic increase in monthly payments to a retired plan member in the event the member's spouse or other contingent annuitant dies prior to the member, and 3) provided for Average Final Compensation to be based on the highest average of three consecutive years compensation. These plan changes increased the projected benefit obligation by $24.6 million.

The Company and its subsidiaries' funding policy is to contribute annually, at a minimum, the amount necessary to satisfy the Internal Revenue Service (IRS) funding standards.

The net pension expense in 1993, 1992 and 1991 was comprised of:

		(Thousands of Dollars)	
	1993	1992	1991
Service cost	**$ 15,868**	$ 14,788	$ 12,196
Interest cost on projected benefit obligation	**38,106**	35,695	33,322
Return on plan assets	**(52,369)**	(34,317)	(79,467)
Amortization of net transition asset at adoption of Statement of Financial Accounting Standards No. 87	**(3,674)**	(3,674)	(3,673)
Other items	**8,219**	(6,317)	39,807
Net pension expense	**$ 6,150**	$ 6,175	$ 2,185

Significant assumptions used in determining net periodic pension cost were:

	1993	1992	1991
Discount rate	**8.2%**	8.2%	8.9%
Expected long-term increase in compensation level	**5.5%**	5.5%	5.5%
Expected weighted average long-term rate of return on assets	**11%**	11%	11%

Variances between actual experience and assumptions for costs and returns on assets are amortized over the average remaining service lives of employees in the plan.

A comparison of the actuarially computed benefit obligations and plan assets at December 31, 1993 and 1992, is presented in the following table. Plan assets are stated at fair value and are comprised primarily of corporate debt and equity securities, a real estate fund and government securities held either directly or in commingled funds.

		(Thousands of Dollars)
	1993	1992
Actuarial present value of benefit obligations:		
Vested	**$ 392,623**	$ 336,632
Nonvested	**39,343**	29,800
	431,966	366,432
Effect of projected future salary increases	**128,294**	110,776
Projected benefit obligation for service rendered to date	**560,260**	477,208
Plan assets at fair value	**(523,548)**	(483,941)
Projected benefit obligation (in excess of) less than plan assets	**(36,712)**	6,733
Unrecognized net loss	**58,252**	34,763
Prior service cost not yet recognized in net periodic pension cost	**34,673**	10,870
Unrecognized net transition asset at January 1, 1986, being recognized over 17 years	**(33,064)**	(36,737)
Prepaid pension asset	**$ 23,149**	$ 15,629

Significant assumptions used in determining the benefit obligations were:

	1993	1992
Discount rate	**7.5%**	8.2%
Expected long-term increase in compensation level	**5.0%**	5.5%

On January 25, 1994, the Board of Directors approved an amendment to the Plan which offers an incentive for early retirement for employees age 55 with 20 years of service as well as a Severance Enhancement Program (SEP) option for these same eligible employees. The Plan amendment and the SEP are effective for the period February 4, 1994 to April 1, 1994. The Plan amendment generally provides for the following retirement enhancements: a) unreduced early retirement benefits, b) three years of additional credited service, and c) a supplement of either a one-time payment equal to $400 for each full year of service to be paid from general corporate funds or a $250 social security supplement each month up to age 62 to be paid by the Plan.

The SEP provides for: a) a one-time severance ranging from $20,000-$90,000, depending on an employee's organization level, b) a continuous years of service bonus (up to 30 years), and c) a cash benefit of $10,000.

Eligible employees may elect to participate in either program. The total cost of the programs is estimated to range between $25 to $32 million. The Company intends to amortize such cost to expense over a period not to exceed approximately five years in accordance with anticipated regulatory treatment of such costs.

Postretirement benefits other than pensions

The Company and its subsidiaries provide certain health care and life insurance benefits for retired employees. A significant portion of the employees become eligible for these benefits if they reach either early or normal retirement age while working for the Company or its subsidiaries. Historically, the Company has recorded the cost of these benefits on a pay-as-you-go basis, consistent with the regulatory treatment. Effective January 1, 1993, the Company and its subsidiaries adopted Statement of Financial Accounting Standards No. 106–"Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106) which requires the accrual, during the years that an employee renders service to the Company, of the expected cost of providing postretirement benefits other than pensions to the employee and the employee's beneficiaries and covered dependents. The additional other postretirement employee benefits (OPEB) costs in 1993 resulting from this new accounting standard, which exceed amounts being recovered through rates, have been deferred for future recovery.

During 1991, the CPUC approved a rate Settlement Agreement (see Note 8) and the Fort St. Vrain Supplemental Settlement Agreement (see Note 2), both of which addressed the accounting and regulatory treatment of the costs of postretirement benefits other than pensions. The rate Settlement Agreement stipulated that the Company would continue to recover such costs as paid until the date new rates are effective. The Fort St. Vrain Supplemental Settlement Agreement stipulated that, on the effective date of new rates (December 1, 1993) the Company would be allowed to recover the costs of postretirement benefits other than pensions as accrued in accordance with the provisions of SFAS 106, modified as follows:

- the actuarial calculation of such liability would include a return on assets that reflects monthly contributions net of benefit payments throughout the year;
- the attribution period would reflect each employee's expected retirement date rather than the full eligibility date;
- a forty-year levelized principal and interest amortization will be used for the transition obligation; and
- the accounting and regulatory treatment for life insurance benefits would remain on an as paid basis.

Pursuant to the Fort St. Vrain Supplemental Settlement Agreement, the Company had anticipated that any difference in expense resulting from the CPUC prescribed approach and the expense required by SFAS 106 would be reflected as a regulatory asset in the consolidated balance sheet and would be recovered from customers over future periods.

In January 1993, however, the Emerging Issues Task Force (EITF) provided guidance as to what additional criteria or evidence is needed for a rate regulated enterprise to recognize a regulatory asset equal to the amount of OPEB costs for which rate recovery has been deferred. Generally, a utility must determine that it is probable that future rates will allow for the recovery of this OPEB regulatory asset. In addition, no later than approximately five years from the date of adoption, rates must include full SFAS 106 costs and the recovery of the regulatory asset established during the deferral period must be accomplished within approximately twenty years. The EITF's conclusions do not include the CPUC approach prescribed in the Fort St. Vrain Supplemental Settlement Agreement.

As a result, and under the provisions of the Fort St. Vrain Supplemental Settlement Agreement, the parties to this Agreement have initiated discussions and negotiations focused on resolving this issue to the mutual acceptance of all parties without disrupting the overall Agreement. These discussions are continuing, and the Company believes it is probable that the matter will ultimately be resolved in a manner that will comply with the conclusions reached by the EITF relative to the recognition of OPEB regulatory assets for which rate recovery has been deferred. Should the currently approved methodology not be modified to conform with the EITF consensus, the Company would be required to record as an expense the difference between the amounts allowed in rates and that required by SFAS 106.

Effective December 1, 1993, the Company began recovering such costs based on the level of expense determined in accordance with the CPUC approach in the Fort St. Vrain Supplemental Settlement Agreement (approximately $18 million on an annual basis for retail jurisdiction). During 1993, the Company deferred $25.9 million of SFAS 106 costs for future recovery. The Company plans to file a FERC rate case in 1994 which will include a request for approval to recover all wholesale jurisdiction SFAS 106 costs. Effective January 1, 1993, Cheyenne began recovering SFAS 106 costs as approved by the WPSC. The Company and Cheyenne intend to fund this plan based on the amounts reflected in cost-of service, consistent with the rate orders.

The OPEB expense on a pay-as-you-go basis was $9.1 million and $8 million for 1992 and 1991, respectively.

The net periodic postretirement benefit cost in 1993 under SFAS 106 was comprised of:

(Thousands of Dollars)	1993
Service cost	$ 4,943
Interest cost on projected benefit obligation	20,828
Return on plan assets	(164)
Amortization of net transition obligation at January 1, 1993, assuming a 20 year amortization period	12,710
Net postretirement benefit cost required by SFAS 106	38,317
1993 OPEB expense recognized in accordance with current regulation	(12,462)
Regulatory asset at December 31, 1993	$ 25,855

The funded status of the plan at December 31, 1993 and January 1, 1993 is as follows:

(Thousands of Dollars)	December 31, 1993	January 1, 1993
Accumulated postretirement benefit obligation:		
Retirees and eligible beneficiaries	$ 86,718	$ 79,692
Other fully eligible plan participants	95,103	95,262
Other active plan participants	98,342	79,238
Total	280,163	254,192
Plan assets at fair value	(476)	–
Accumulated benefit obligation in excess of plan assets	279,687	254,192
Unrecognized net loss	(10,059)	–
Unrecognized transition obligation	(241,483)	(254,192)
Accrued postretirement benefit obligation	$ 28,145	$ –

Significant assumptions used in determining the accumulated postretirement benefit obligation were:

	December 31, 1993	January 1, 1993
Discount rate	7.5%	8.2%
Ultimate health care cost trend rate	5.3%	6.0%
Expected long-term increase in compensation level	5.0%	5.5%

The assumed health care cost trend rate for 1993 is 12%, decreasing to 5.3% in 0.5% annual increments. A 1% increase in the assumed health care cost trend will increase the estimated total accumulated benefit obligation by $37.7 million, and the service and interest cost components of net periodic postretirement benefit costs by $5.2 million.

Postemployment benefits

In November 1992, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 112–"Employers' Accounting for Postemployment Benefits" (SFAS 112) which establishes the accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (postemployment benefits). This statement became effective January 1, 1994 and the Company has estimated its benefit obligation to be approximately $32 million, assuming a 7.5% discount rate. The Company believes it is probable that it will receive CPUC approval to recover these costs in future rates and, therefore, the application of the new standard will not have a material impact on the Company's financial position or results of operations as a regulatory asset and a corresponding liability will be established on the consolidated balance sheet.

Incentive compensation

The Company's shareholders approved the Omnibus Incentive Plan at the 1992 Annual Shareholders Meeting. The Omnibus Incentive Plan provides for annual and long-term incentive awards for officers and management employees. One million shares of common stock have been authorized for awards under the Plan as it allows for the issuance of stock options and/or restricted shares. The stock options are issued at the fair market value of the Company's common

stock at the date of issue and vest over a three-year period. Options were granted to eligible officers in 1993. Cash and restricted stock awards were made under the Omnibus Incentive Plan in 1994, since goals were met in 1993.

During 1992, the Company established the Employee Incentive Plan which recognizes the contribution of all employees toward corporate financial goals. This plan, which was effective beginning in 1993, provides for a cash award to employees if annual corporate performance goals are met. Performance goals were met in 1993, and a cash award was paid in early 1994.

The expenses accrued under both the incentive plans totaled $5.2 million in 1993 and $0 in 1992.

11. Financial Instruments

Fair value of financial instruments

The estimated fair values of the Company's financial instruments are as follows:

(Thousands of Dollars)

	1993		1992	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Assets				
Cash and temporary cash investments	$ 18,038	$ 18,038	$ 51,155	$ 51,155
Investments, at cost	6,595	6,642	15,221	16,535
Liabilities				
Notes payable and commercial paper	276,875	276,418	250,626	249,760
Preferred stock subject to mandatory redemption	45,455	46,650	45,654	45,895
Dividends payable	33,234	33,234	32,248	32,248
Accrued interest	29,507	29,507	31,032	31,032
Customers' deposits	16,225	16,225	16,807	16,807
Other deposits	6,231	6,231	5,644	5,644
Long-term debt	1,195,669	1,255,768	1,198,007	1,218,998

The following methods and assumptions were used to estimate the fair value of each class of financial instrument.

Cash and temporary cash investments, dividends payable and accrued interest

The carrying amount is a reasonable approximation of fair value due to the nature and short-term maturity of these financial instruments.

Investments, at cost

The fair value of the majority of these investments is estimated based on quoted market prices for similar investments. For the remaining investments, the carrying amount is a reasonable approximation of fair value due to the nature of the instruments.

Notes payable and commercial paper

The carrying amount of notes payable is a reasonable approximation of fair value due to their nature and short-term maturity. For commercial paper, the fair value was estimated based upon the carrying value less unaccreted interest.

Preferred stock subject to mandatory redemption

The fair value is based on quoted market prices for similar instruments.

Customers' deposits

Due to the nature of these deposits, the carrying amount is a reasonable approximation of fair value.

Other deposits

Other long-term deposits from third parties are included in other deferred credits. Due to the nature of these deposits, the carrying amount approximates fair value.

Long-term debt

The estimated fair value of the Company's debt was based on quoted market prices of the same or similar securities. Anticipated regulatory treatment of the difference between carrying and fair value of the Company's long-term debt, if in fact it were settled at amounts approximating those above, would dictate that these amounts be used to reduce or increase the Company's rates over a prescribed amortization period. Accordingly, the settlement would not result in a material impact on the Company's financial position or results of operations.

Other items

In accordance with NRC decommissioning funding requirements for nuclear power reactors, the Company has obtained a $92 million irrevocable letter of credit which bears a market interest rate. The NRC is the beneficiary of this letter of credit. At December 31, 1993 and 1992, no amounts were outstanding under this letter of credit. In general, such letter of credit may be exercised by the NRC in the event the Company is in default of its performance obligations under the decommissioning plan.

Concentration of Credit Risk

The Company is required to provide service and grant credit to a diverse customer base within its service territory. The Company may require security deposits prior to providing service to customers depending upon an assessment of credit worthiness. The Company reviews customer accounts receivable on a regular basis and has in effect an uncollectible accounts policy. No individual customer or group of customers engaged in similar activities represent a material concentration of credit risk to the Company.

12. Income Tax Expense

Income tax expense consists of the following:

		(Thousands of Dollars)	
	1993	1992	1991
Current income taxes:			
Federal	**$34,684**	$34,265	$40,156
State	**(2,208)**	1,513	8,240
Total current income taxes	**32,476**	35,778	48,396
Deferred income taxes	**33,435**	22,509	26,122
Investment tax credits–net	**(4,917)**	(5,138)	(5,230)
Total provision for income taxes	**$60,994**	$53,149	$69,288

The Company and its subsidiaries adopted SFAS 109 on January 1, 1993, the effective date of the new statement. SFAS 109 requires that the liability approach be used to account for income taxes. In general, under this method deferred tax liabilities and assets are determined based on the temporary differences between the financial statement and tax return bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. As discussed below, the impact of the adoption of SFAS 109 is not material to the Company's results of operations and, therefore, has not been reflected as the cumulative effect of a change in accounting principle. As a result, the effect of adoption is included in income tax expense in the accompanying consolidated statement of income for the year ended December 31, 1993.

The Company and its regulated subsidiaries have historically provided for deferred income taxes to the extent allowed by their regulatory agencies whereby deferred taxes were not provided on all differences between financial statement and taxable income (the flow-through method). However, as of January 1, 1993, in accordance with SFAS 109, a $118.4 million increase in the net accumulated deferred income tax liability and a corresponding regulatory asset were recognized on the consolidated balance sheet to give effect to temporary differences for which deferred taxes were not previously required to be provided. The regulatory asset represents temporary differences primarily associated with prior flow-through amounts and the equity component of allowance for funds used during construction, net of temporary differences related to unamortized investment tax credits and excess deferred taxes that have resulted from historical reductions in tax rates.

Effective December 1, 1993, pursuant to a CPUC order, the Company adopted full income tax normalization for rate regulatory purposes with the regulatory tax asset being recovered over a thirteen year period.

The effect of the adoption of SFAS 109 on nonregulated activities increased net income by approximately $1.9 million during the year ended December 31, 1993, primarily due to the adjustment to deferred income taxes on nonregulated activities accrued in prior years at tax rates in excess of the current enacted tax rates. During 1993, the Federal statutory income tax rate was raised from 34% to 35%, retroactive to January 1, 1993. The impact of this tax rate change on the Company was to increase the net deferred income tax liability by $16.8 million, of which $16.7 million increased the regulatory asset related to income taxes.

The sources of significant timing differences which gave rise to deferred income taxes for years prior to the adoption of SFAS 109 were as follows:

	(Thousands of Dollars) 1992	1991
Contributions in aid of construction	$ (8,006)	$ (4,789)
Accelerated depreciation	17,789	20,721
Net unbilled revenues	(914)	(7,552)
Fort St. Vrain defueling and decommissioning	15,831	12,531
Termination of Synhytech project	(10,063)	–
Loss on sale of real estate investments	7,986	–
Alternative minimum tax	145	2,231
Other book-tax timing differences	(259)	2,980
Total deferred income tax expense	$ 22,509	$ 26,122

The components of accumulated deferred income taxes as of December 31, 1993 and January 1, 1993 were as follows:

	(Thousands of Dollars) **December 31, 1993**	January 1, 1993
Current portion of accumulated deferred income taxes:		
Deferred tax assets	**$ 14,414**	$ 21,930
Deferred tax liabilities	**(10,213)**	(345)
Net current deferred tax assets	**4,201**	21,585
Accumulated deferred income taxes:		
Deferred tax liabilities	**582,780**	461,727
Deferred tax assets	**(137,250)**	(48,350)
Net accumulated deferred tax liabilities	**445,530**	413,377
Net deferred income tax liability	**$ 441,329**	$ 391,792

The tax effect of significant temporary differences representing deferred tax assets and liabilities as of December 31, 1993 and January 1, 1993 were as follows:

	(Thousands of Dollars) **December 31, 1993**	January 1, 1993
Deferred income tax liabilities (assets):		
Accelerated depreciation and amortization	**$ 313,275**	$ 283,819
Plant basis differences (prior flow-through)	**199,820**	175,588
Allowance for equity funds used during construction	**51,500**	44,617
Pensions	**31,689**	26,172
Investment tax credits	**(76,841)**	(76,689)
Contributions in aid of construction	**(33,063)**	(27,177)
Other–net	**(45,051)**	(34,538)
Net deferred income tax liability	**$ 441,329**	$ 391,792

A valuation allowance has not been recorded at December 31, 1993 and January 1, 1993, as the Company expects that all deferred income tax assets will be realized in the future.

As of December 31, 1993, the Company has cumulative AMT carryforwards of approximately $6.3 million.

A reconciliation of the statutory U.S. income tax rates and the effective tax rates follows:

(Thousands of Dollars)

	1993		1992		1991	
Tax computed at U.S. statutory rate on pre-tax accounting income	**$76,424**	**35.0%**	$64,522	34.0%	$74,454	34.0%
Increase (decrease) in tax from:						
Allowance for funds used during construction	**(4,369)**	**(2.0)**	(3,827)	(2.0)	(2,767)	(1.3)
Amortization of investment tax credits	**(4,889)**	**(2.2)**	(5,128)	(2.7)	(5,095)	(2.3)
State income taxes, net of federal income tax benefit	**(1,435)**	**(0.7)**	997	0.5	5,431	2.5
Capitalized software, net of amortization	**(4,820)**	**(2.2)**	(7,115)	(3.7)	(5,533)	(2.5)
Capitalized overheads	**7,170**	**3.3**	7,112	3.7	4,732	2.1
Lease amortization	**3,692**	**1.7**	3,407	1.8	2,992	1.4
Cash surrender value of life insurance policies	**(6,386)**	**(2.9)**	(4,620)	(2.4)	(2,572)	(1.2)
Implementation of SFAS 109	**(1,911)**	**(0.9)**	–	–	–	–
Other–net	**(2,482)**	**(1.1)**	(2,199)	(1.2)	(2,354)	(1.1)
Total income taxes	**$60,994**	**28.0%**	$53,149	28.0%	$69,288	31.6%

13. Supplementary Income Statement Information

(Thousands of Dollars)

	1993	1992	1991
Taxes (other than income taxes):			
Real estate and personal property taxes	**$55,238**	$51,378	$43,746
Social security taxes	**21,226**	20,752	20,398
City and state use taxes	**8,895**	8,072	8,397
Miscellaneous taxes	**7,398**	7,839	7,045
	$92,757	$88,041	$79,586
Charged:			
Directly to income:			
Operating expenses	**$86,775**	$82,040	$74,335
Other	**128**	155	138
To property, plant and equipment and various other accounts	**5,854**	5,846	5,113
	$92,757	$88,041	$79,586

The amounts of maintenance and repairs charged to clearing and other accounts and not shown separately in the consolidated financial statements were not material. There were no charges for royalties. The amounts of advertising costs were less than 1% of gross revenues.

14. Segments of Business

Segment information for the year ended December 31, 1993 is as follows:

(Thousands of Dollars)

	Electric	Gas	Other	Total
Operating revenues	$ 1,337,053	$ 628,324	$ 33,308	$ 1,998,685
Operating expenses, excluding depreciation and income taxes	953,049	560,593	2,312	1,515,954
Depreciation and amortization	109,958	28,305	2,541	140,804
Total operating expenses*	1,063,007	588,898	4,853	1,656,758
Operating income*	$ 274,046	$ 39,426	$ 28,455	$ 341,927
Plant construction expenditures**	$ 205,153	$ 86,867	$ 1,495	$ 293,515
Identifiable assets, December 31, 1993:				
Property, plant and equipment**	$ 2,413,580	$ 695,456	$ 84,100	$ 3,193,136
Materials and supplies	$ 64,674	$ 12,993	$ 65	77,732
Fuel inventory	$ 35,337	$ —	$ 147	35,484
Gas in underground storage (1)	$ —	$ 41,130	$ —	41,130
Other corporate assets				699,146
				$ 4,046,628

(1) Additional gas storage was purchased as part of the Company's implementation strategy associated with FERC Order 636.

Segment information for the year ended December 31, 1992 is as follows:

(Thousands of Dollars)

	Electric	Gas (2)	Other (3)	Total
Operating revenues	$ 1,260,769	$ 568,886	$ 32,618	$ 1,862,273
Operating expenses, excluding depreciation and income taxes	886,215	529,225	16,740	1,432,180
Depreciation and amortization	97,274	27,621	2,422	127,317
Total operating expenses*	983,489	556,846	19,162	1,559,497
Operating income*	$ 277,280	$ 12,040	$ 13,456	$ 302,776
Plant construction expenditures**	$ 185,170	$ 73,685	$ 2,811	$ 261,666
Identifiable assets, December 31, 1992:				
Property, plant and equipment**	$ 2,331,116	$ 653,898	$ 92,495	$ 3,077,509
Materials and supplies	$ 67,618	$ 13,302	$ 82	81,002
Fuel inventory	$ 33,384	$ —	$ 189	33,573
Gas in underground storage	$ —	$ 14,393	$ —	14,393
Other corporate assets				553,106
				$ 3,759,583

(2) Includes additional expense of approximately $26.9 million associated with the termination of the Synhytech project.
(3) Includes additional expense of approximately $11.4 million associated with the loss on sale of BCC real estate properties.

* Before income taxes.
** Includes allocation of common utility property.

Segment information for the year ended December 31, 1991 is as follows:

(Thousands of Dollars)

	Electric	Gas	Other	Total
Operating revenues	$1,180,501	$587,609	$ 26,794	$1,794,904
Operating expenses, excluding depreciation and income taxes	847,798	518,157	4,355	1,370,310
Depreciation and amortization	83,416	25,831	2,481	111,728
Total operating expenses*	931,214	543,988	6,836	1,482,038
Operating income*	$ 249,287	$ 43,621	$ 19,958	$ 312,866
Plant construction expenditures**	$ 155,457	$ 99,771	$ 5,476	$ 260,704
Identifiable assets, December 31, 1991:				
Property, plant and equipment**	$2,006,776	$637,083	$101,941	$2,745,800
Materials and supplies	$ 65,242	$ 13,059	$ 66	78,367
Fuel inventory	$ 34,238	$ –	$ 209	34,447
Gas in underground storage	$ –	$ 14,803	$ –	14,803
Other corporate assets				589,251
				$3,462,668

* Before income taxes.
** Includes allocation of common utility property.

15. Operating Leases

The Company and its subsidiaries maintain operating leases for equipment and facilities used in the normal course of business. The majority of these operating leases are under a leasing program that has initial noncancelable terms of one year, while the remaining operating leases have various terms. These leases may be renewed or replaced. No material restrictions exist in these leasing agreements concerning dividends, additional debt, or further leasing. Rental expense for 1993, 1992 and 1991 was $28.1 million, $25.1 million and $21.7 million, respectively. At December 31, 1993, estimated future minimum rental payments applicable to noncancelable operating leases were as follows:

(Thousands of Dollars)

Years ending December 31	
1994	$ 22,345
1995	17,310
1996	14,531
1997	12,755
1998	12,109
1999 and thereafter	33,569
Total minimum rental payments	$112,619

16. Quarterly Financial Data (Unaudited)

The following summarized quarterly information for 1993 and 1992 is unaudited but includes all adjustments (consisting only of normal recurring accruals) which the Company considers necessary for a fair presentation of the results for the periods. Information for any one quarterly period is not necessarily indicative of the results which may be expected for a twelve month period due to seasonal and other factors.

(Thousands except per share data)

1993 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues	$607,389	$448,001	$422,353	$520,942
Operating income	$ 88,014	$ 49,681	$ 56,575	$ 86,663
Net income	$ 58,687	$ 20,435	$ 25,527	$ 52,711
Earnings available for common stock	$ 55,678	$ 17,426	$ 22,519	$ 49,706
Weighted average common shares outstanding	58,997	59,535	59,925	60,324
Earnings per weighted average common share	$0.94	$0.29	$0.38	$0.82

(Thousands except per share data)

1992 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues	$526,874	$422,489	$407,326	$505,584
Operating income	$ 71,504	$ 58,282	$ 61,323	$ 58,518
Net income	$ 46,204	$ 28,948	$ 29,840	$ 31,631
Earnings available for common stock	$ 43,180	$ 25,924	$ 26,820	$ 28,622
Weighted average common shares outstanding	56,701	57,382	57,840	58,308
Earnings per weighted average common share	$0.76	$0.45	$0.46	$0.49

SHAREHOLDER INFORMATION

Public Service Company of Colorado and Subsidiaries

Where to Buy Stock
The company's common and preferred stock may be purchased through a brokerage firm. A shareholder of common stock registered in their own name may also purchase additional shares through the Automatic Dividend Reinvestment and Common Stock Purchase Plan (DRP).

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

Dividend Reinvestment Plan
The company's DRP provides common stock shareholders of record an economical and convenient method of purchasing additional shares of common stock. Participants in the Plan may reinvest cash dividends on all or a portion of their shares and/or make optional cash payments.

Common stock shareholders whose stock is registered in names other than their own may participate in the DRP for reinvestment of dividends, provided the broker or fiduciary who holds such stock in nominee name is willing to participate in the DRP.

Safekeeping
Shareholders may request safekeeping of stock certificates, thus guarding against loss or theft. To participate, mail your stock certificate by insured mail with a note requesting safekeeping. An internal record of the shares will be maintained. If a stock certificate is required at a future date, notify our office that issuance is desired.

Address Changes
When an address change is required, notify the Shareholder Services Dept., in writing, as soon as possible. Please provide your account number, account name, new address and old address.

Service Fees
Fees are charged for certain services such as copies of 1099 DIV's, paid checks and duplicate DRP statements. For information regarding any charge or research fee, please contact the Shareholder Services Dept.

Stock Trading
The company's common stock is listed for trading on the New York, Chicago, and Pacific Stock Exchanges. Three series of cumulative preferred stock are actively traded: 4.25% ($100 par value) on the American Stock Exchange; 7.15 % ($100 par value); and 8.40% ($25 par value) on the New York Stock Exchange. The other series of preferred stock are not actively traded and are not listed on an exchange.

Shareholder Inquiries
Inquiries regarding stock transfer requirements, direct deposit of dividends, lost or stolen checks or certificates, address changes or other matters should be directed to the Shareholder Services Dept. The following telephone number is available during business hours, which are **8:00 a.m. to 5:00 p.m. (MST) (303) 294-2566.**

Quarterly Report Mailings
Shareholders whose stock is held in street name by their broker do not receive quarterly shareholder reports. If your stock is held in street name and you want to receive quarterly reports, please contact the Shareholder Services Dept. to place your name on a mailing list.

Headquarters
Public Service Company of Colorado
1225 17th Street, Post Office Box 840
Denver, CO 80201-0840
Telephone: (303) 571-7511

Transfer Agent, Paying Agent and Registrar for all Classes of Stock and Dividend Reinvestment Plan Agent
Public Service Company of Colorado
Shareholder Services Dept.
Post Office Box 840, Suite 300
Denver, CO 80201-0840
Telephone: (303) 294-2566
FAX Number: (303) 294-2583

Transfer Agent and Registrar for Long-Term Debt
Morgan Guaranty Trust Company of New York
Corporate Trust Operations
55 Exchange Place
New York, NY 10260

Investor Relations
(303) 294-2592

Stock Symbols
Common Ticker Symbol: PSR
Newspaper Listing:
PubSvcCol or PSvCol

Annual Meeting
Wednesday, May 11, 1994
10:00 a.m.
Radisson Hotel
1550 Court Place
Denver, Colorado

Your opinion is valued. Please take a few minutes to complete and return the pre-addressed, postage-paid, survey card below. This information will help us to better meet your needs, wants and expectations in the future.

SHAREHOLDER SURVEY

1. Please indicate your interest in the following issues:
Please circle a number for each issue.

	Not Interested				Very Interested
Regulation	1	2	3	4	5
Fort St. Vrain	1	2	3	4	5
Competition	1	2	3	4	5
Customer retention/growth	1	2	3	4	5
Dividend– security/growth	1	2	3	4	5
Emerging technologies	1	2	3	4	5
Service territory economics	1	2	3	4	5
Environmental– energy conservation	1	2	3	4	5

2. Which factors influence your Public Service Co. of Colorado investment decision?
Please rank from most important (1) to least important (7).

__ Dividend
__ Stability of industry
__ Management/Competition
__ Stock price appreciation
__ Service territory economics
__ Combination electric and gas utility vs. single server company
__ Other ______________________

3. Which of the following communications did you use last year?
Please rank from most valuable (1) to least valuable (7).

__ Annual Report
__ Quarterly Reports
__ 10-K
__ 10-Q
__ Direct Phone Communication
__ Investor Club Presentations
__ Other ______________

4. If available, which communications would be of interest?
Please check the appropriate box(es).

☐ PSCo stock price phone hotline
☐ Regional shareholder meetings
☐ Current issues updates (fact sheet)
☐ Colorado economy updates (fact sheet)
☐ Electronic bulletin board of financial/company news

5. If available, which services would be of interest?
Please check the appropriate box(es).

☐ Initial purchase of stock directly from PSCo
☐ Sale of stock directly to PSCo
☐ Automatic monthly investment/electronic stock purchase
☐ Book entry ownership only (no certificate issuance)

SHAREHOLDER PROFILE

Please circle one answer to each question.

What is your interest in PSCo?
1. Individual shareholder
2. Institutional shareholder
3. Financial analyst
4. Stockbroker
5. PSCo employee
6. NAIC member
7. Potential investor
8. Other ____________

Age category?
1. Under 25
2. 25-44
3. 45-64
4. 65 or over

PSCo shares owned? (include dividend reinvestment)
1. Under 50
2. 50-100
3. 101-500
4. 501-1,000
5. 1,001-2,000
6. Over 2,000

How long have you been a PSCo shareholder?
1. Less than 1 year
2. 1-2 years
3. 3-5 years
4. 6-10 years
5. 11-20 years
6. Over 20 years

Principal reason for holding PSCo stock?
1. Dividend income
2. Income plus price appreciation
3. Price appreciation
4. Other ____________

Which most influenced you to acquire PSCo stock?
1. Personal research
2. Stockbroker
3. Friend or relative
4. Gift/inheritance
5. NAIC
6. Other ____________

Please indicate type of work:
1. Professional/technical
2. Clerical/office/sales
3. Retired
4. Proprietor
5. Domestic/homemaker
6. Business/managerial
7. Government/military
8. Student
9. Unemployed
10. Other ____________

What is your biggest concern regarding PSCo?

____
____
____
____

What is your zip code? ____________________

If you have any questions please call:
Shareholder administration/shareholder account
(303) 294-2566
Company/industry issues
(303) 294-2592

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BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

BOARD OF DIRECTORS

D. D. Hock
Denver, CO (1985)
Chairman of the Board, President and Chief Executive Officer
Age 58

Collis P. Chandler, Jr.
Denver, CO (1985)
Chairman of the Board and Chief Executive Officer
Chandler & Associates, Inc.
Age 67

Doris M. Drury, PhD
Denver, CO (1975)
Regis College
Special Assistant to the President;
President, Center for Business and Economic Forecasting, Inc.
Age 67

Thomas T. Farley
Pueblo, CO (1983)
Attorney at Law
Petersen & Fonda Professional Corp.
Age 59

Gayle L. Greer
Denver, CO (1986)
Vice President, Time Warner Cable
Age 52

A. Barry Hirschfeld
Denver, CO (1988)
President, A. B. Hirschfeld Press, Inc.
Age 51

George B. McKinley
Evanston, WY (1976)
Chairman and Chief Executive Officer
First National Bank of Evanston,
President, First McKinley Corp.
Age 66

Will F. Nicholson, Jr.
Denver, CO (1981)
Chairman, President and Chief Executive Officer
Colorado National Bankshares, Inc.
Age 64

J. Michael Powers
Cheyenne, WY (1978)
President, Powers Products Co. and Powers Brick and Tile
Age 51

Thomas E. Rodriguez
Denver, CO (1986)
President, Thomas E. Rodriguez & Associates, P.C.
Age 49

Rodney E. Slifer
Vail, CO (1988)
Partner
Slifer, Smith & Frampton
Age 59

W. Thomas Stephens
Denver, CO (1989)
Chairman, President and Chief Executive Officer
Manville Corporation
Age 51

Robert G. Tointon
Greeley, CO (1988)
President and Chief Executive Officer
Phelps-Tointon, Inc.
Age 60

EXECUTIVE COMMITTEE

D. D. Hock
Doris M. Drury
George B. McKinley
Will F. Nicholson, Jr.
Robert G. Tointon

AUDIT COMMITTEE

J. Michael Powers
Thomas T. Farley
Gayle L. Greer
Thomas E. Rodriguez

PENSION INVESTMENT COMMITTEE

W. T. Stephens
A. Barry Hirschfeld
Rodney E. Slifer

COMPENSATION COMMITTEE

Doris M. Drury
George B. McKinley
Will F. Nicholson, Jr.
W. T. Stephens
Robert G. Tointon

EXECUTIVE OFFICERS

D. D. Hock
Chairman of the Board, President and Chief Executive Officer
Age 58 (31)

Clark B. Ewald
Senior Vice President
Customers
Age 59 (34)

Richard C. Kelly
Senior Vice President
Finance and Administration
Chief Financial Officer
Age 47 (25)

Patrick W. McCarter
Senior Vice President
Electric Operations
Age 56 (34)

W. Wayne Brown†
Corporate Secretary and Controller
Age 43 (21)

A. C. Crawford
Vice President
Electric Production
Age 61 (4)

Dale V. Fetchenhier
Vice President
Information Technology and Services
Age 60 (36)

Ross C. King, Jr.
Vice President
Metropolitan Customer Operations
Age 52 (27)

William J. Martin
Vice President
Electric Engineering and Planning
Age 62 (36)

Earl E. McLaughlin, Jr.
Vice President
Marketing, Customer Services and Support Services
Age 53 (33)

James H. Ranniger
Vice President
Rates and Regulations
Age 57 (35)

Philip D. Shaffer
Vice President
Division Customer Operations
Age 48 (20)

Marilyn E. Taylor
Vice President
Administrative Services
Age 51 (6)

Ralph Sargent III††
Vice President
Finance, Planning and Communication and Treasurer
Age 44 (15)

OTHER OFFICERS

Thomas W. Hess
Assistant Secretary
Age 44 (21)

Edward L. Meaders
Assistant Secretary
Age 37 (14)

Carol J. Peterson
Assistant Secretary
Age 51 (7)

J. Anthony Terrell
Assistant Secretary and Assistant Treasurer
Age 50 (3)

Stephen H. Whitcomb
Assistant Secretary
Age 43 (18)

William E. Lewis
Assistant Treasurer
Age 44 (22)

Michael D. Pritchard
Assistant Treasurer
Age 47 (22)

Debra L. Sago
Assistant Treasurer
Age 38 (14)

MANAGERS, GEOGRAPHIC DIVISIONS

S. G. Arnold
Foothills Region and Boulder Division
Age 40 (18)

Bill L. Croley
Denver Metropolitan
Age 53 (21)

David P. Davia
Northern Metropolitan Region
Age 48 (25)

Anthony J. DeNovellis
Southern Region & Pueblo Division
Age 45 (23)

Michael J. Geile
Home Light Division
Age 51 (29)

W. Bruce Hansford
Northern Division
Age 52 (25)

Douglas C. Lockhart
Western Region
Age 51 (29)

Joseph O. Marquez
San Luis Valley
Age 56 (33)

Mary M. McMillan
Front Range
Age 40 (14)

Phillip L. Noll
Mountain Division
Age 54 (35)

V. Clark Stephens, Jr.
Southeast Metropolitan Division
Age 56 (33)

George A. Senkus
Southwest Metropolitan Region
Age 57 (26)

PRESIDENTS SUBSIDIARY COMPANIES*

D. D. Hock
1480 Welton, Inc.
Fuel Resources Development Co.
Green and Clear Lakes Company
Natural Fuels Corporation
PS Colorado Credit Corporation
PSR Investments, Inc.
WestGas Gathering, Inc.
WestGas InterState, Inc.
WestGas TransColorado, Inc.
Age 58 (31)

Philip D. Shaffer
Cheyenne Light, Fuel and Power Company
Age 48 (20)

* Effective November 30, 1993, Bannock Center Corporation was dissolved.

† Elected Corporate Secretary, effective November 23, 1993

†† Elected Vice President, Finance, Planning and Communication, effective July 27, 1993

AUDITORS

Arthur Andersen & Co.
717 - 17th Street, Suite 1900
Denver, Colorado 80202

( ) Denotes years of service or association with the Company through December, 1993

Ages as of December 31, 1993

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