Public Service

Public Service
Company of Colorado

16805 WCR 19 1/2, Platteville, Colorado 80651

April 3, 1992
Fort St. Vrain
Unit No. 1
P-92148

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

Docket No. 50-267

SUBJECT: ANNUAL FINANCIAL REPORT

Gentlemen:

Enclosed are ten (10) copies of the 1991 Annual Report for Public Service Company of Colorado, including the certified financial statements for 1991. This document is submitted for your information and use in accordance with 10 CFR 50.71(b).

Sincerely,

F. J. Novachek
Deputy Program Manager

FJN/LMG

Enclosures

cc: Regional Administrator, Region IV

Mr. J. B. Baird
Senior Resident Inspector
Fort St. Vrain

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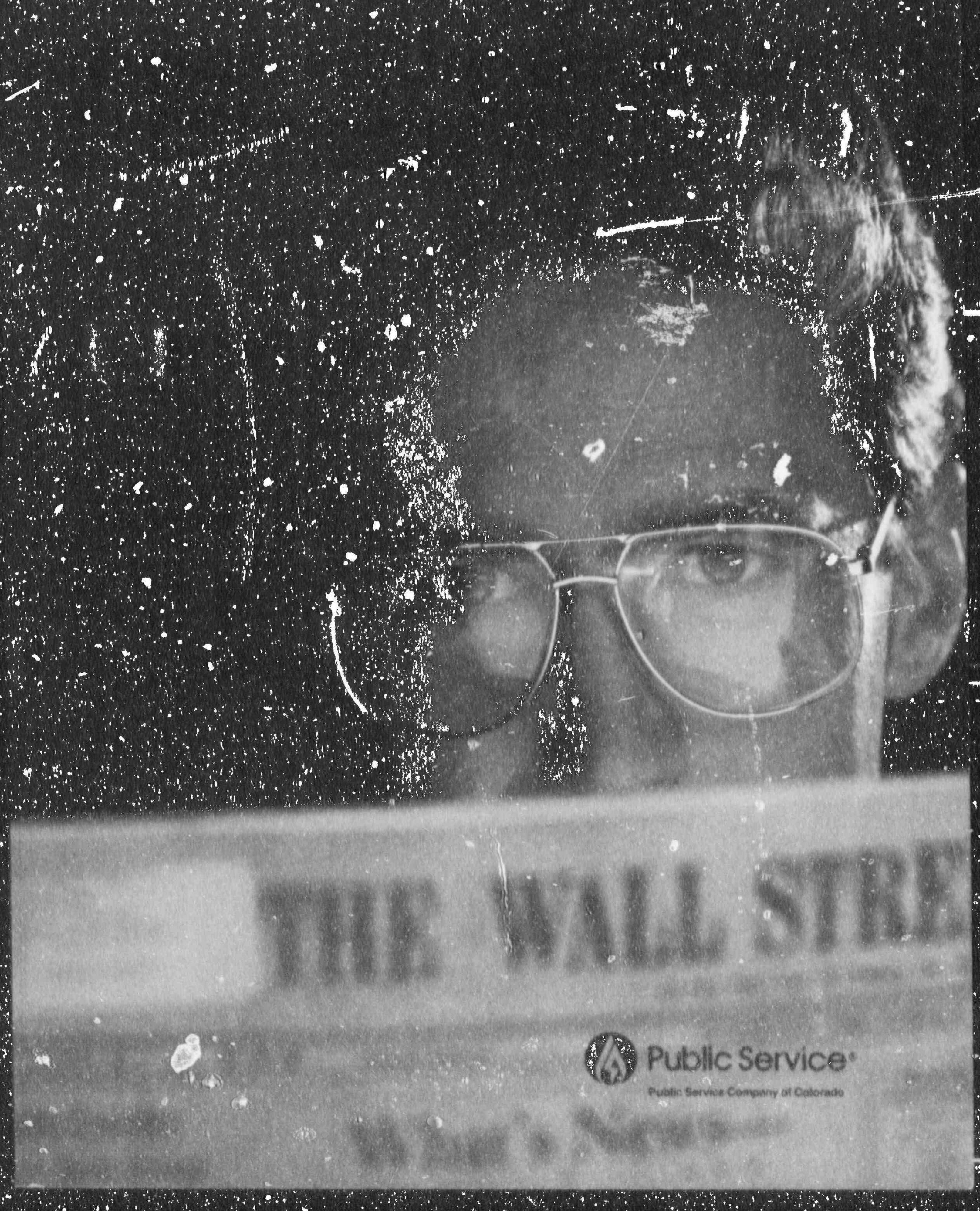
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Public Service
Public Service Company of Colorado

About Public Service Co. of Colorado

As the nation's eighth largest investor-owned electric and natural gas utility, Public Service Co. serves approximately 2.5 million people throughout Colorado and the Cheyenne, Wyoming area.

Headquartered in Denver, Colorado, the company operates seven steam-electric plants, six hydroelectric facilities, a downtown Denver thermal energy service and an extensive natural gas system that includes more than 13,300 miles of natural gas distribution piping.

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

Western Gas Supply Company, one of the largest natural gas pipeline systems in the Rocky Mountain region;

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

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

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

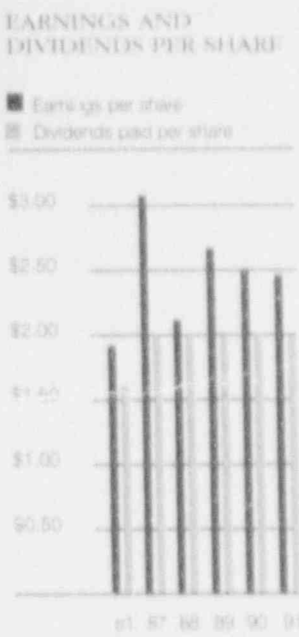
Bannock Center Corporation, a real estate investment company;

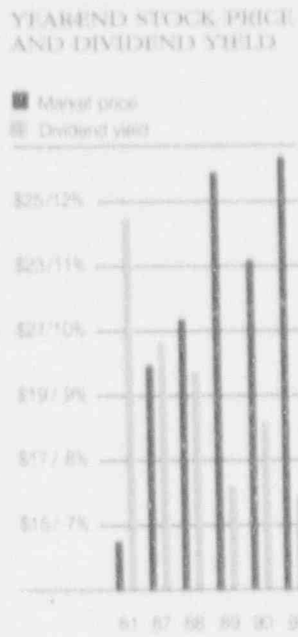
Welton Properties, a company that owns and manages real estate for utility operations, and

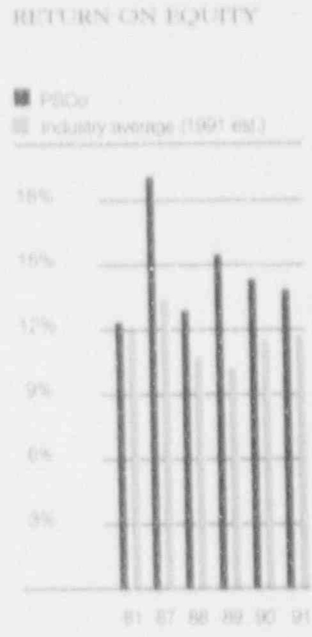
P.S. Colorado Credit Corporation and **P.S.R. Investment, Inc.**, two finance subsidiaries.

Contents

Financial and Operations Highlights







Financial	1991	1990	% Change
Earnings Per Weighted Average Share	**$2.48**	$2.49	(0.4)
Dividends Per Share	**$2.00**	$2.00	–
Return on Average Common Shareholder Equity	**13.8%**	14.3%	(3.5)
Common Shareholder Equity–% of Capitalization (year-end)	**42.8%**	41.8%	2.4
Operating Revenues (000)	**$1,794,904**	$1,733,939	3.5
Operating Expenses (000)	**$1,551,326**	$1,495,533	3.7
Net Income (000)	**$ 149,693**	$ 146,144	2.4
Construction Expenditures (000)	**$ 260,704**	$ 261,221	(0.2)
Gross Plant Investment (000)	**$4,273,744**	$4,038,771	5.8
Number of Employees	**6,565**	6,611	(0.7)
Common Stock Shareholders	**56,038**	55,945	0.2
Common Stock Shares Outstanding (000)	**56,294**	54,320	3.6
Operations			
Electric Revenues (000)	**$1,180,501**	$1,145,915	3.0
Kilowatt-Hour Sales (millions)	**20,452**	20,148	1.5
Electric Customers	**1,000,662**	990,633	1.0
Gas Revenues (000)	**$ 587,609**	$ 561,712	4.6
Mcf Deliveries (000)	**232,702**	210,927	10.3
Gas Customers	**878,579**	865,399	1.5

Percentage of Male, Female and Minority Employees at Year-End 1990 and 1991

	Male		Female		Native American		Asian/Pacific Islanders		Hispanic		Black		Total Minorities		White		Total	
	1990	1991	1990	1991	1990	1991	1990	1991	1990	1991	1990	1991	1990	1991	1990	1991	1990	1991
Total Work Force	4,999	4,922	1,612	1,643	16	25	86	87	860	871	383	366	1,347	1,349	5,264	5,216	6,611	6,565
% of Total	75.6	75.0	24.4	24.9	0.2	0.3	1.3	1.3	13.0	13.2	5.7	5.5	20.4	20.5	79.6	79.4	100	100
Management	804	780	131	138	1	2	12	13	55	52	31	27	99	94	836	824	935	918
% of Management	85.8	84.9	14.0	15.0	0.1	0.2	1.2	1.4	5.9	5.6	3.3	2.9	10.6	10.2	89.4	89.7	100	100
Non-Management	4,195	4,142	1,481	1,505	17	23	74	74	805	819	352	339	1,248	1,255	4,428	4,392	5,676	5,647
% of Non-Management	73.9	73.3	26.0	26.7	0.3	0.4	1.3	1.3	14.2	14.5	6.2	6.0	21.9	22.2	78.0	77.7	100	100

To Our Shareholders

1991 was a year of major decisions for Public Service Company of Colorado. I am very proud of what our management team and our employees were able to achieve in spite of some of the most difficult financial challenges we have ever faced. While our 1991 earnings of $2.48 per share (one cent less than last year) would suggest very little, if any, progress toward our goal of increasing total return for our shareholders, the many critical issues addressed and resolved during the year demonstrate that this was in fact an impressive achievement. The specifics of these issues and how we addressed them are highlighted in this annual report. After reading it, I am confident you will agree that 1991 was a very successful year for our company. It was a year in which we made some very important decisions and renewed our commitment to cost effective, high quality energy services.

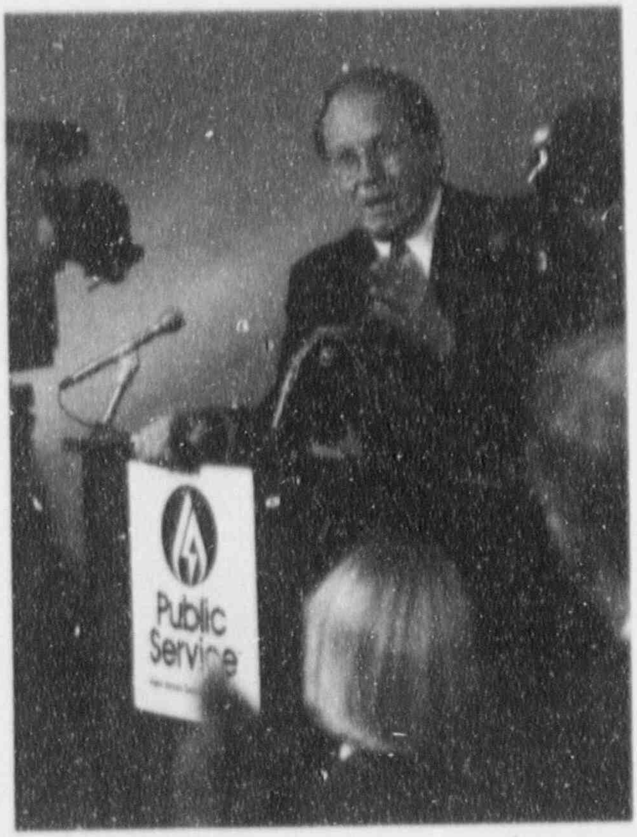
Looking ahead, it is clear that the many changes in the business environment, and specifically in the electric and natural gas industries, will have a major impact on our company. These changes include increasing deregulation resulting in intense competition for some segments of our traditional utility investments and markets; an accelerating emphasis on energy conservation and demand-side supply, along with increasing regulatory involvement in planning for future energy resources; and continuing consolidation of systems and companies within both industries.

These changes, as well as the capital restraints resulting from the financial difficulties we have experienced since 1986, led us to a reevaluation of our corporate strategies in 1991. We decided, among other things, to concentrate our efforts on the core electric and gas businesses. As a result, we have begun a reassessment of our investment in business units outside that core.

While much of the country suffered the effects of a recession in 1991, the economy in our service territory outpaced most of the nation– resulting in steady, albeit slow, customer and sales growth. Our marketing strategy for the rest of the decade will be directed at retaining our present customer base and taking advantage of growth opportunities with existing and new customers.

Regulation will continue to be a key issue. As a part of our 1991 settlement agreement with the Colorado Public Utilities Commission, we are required to file a rate case by November 1992. With the many changes in the regulatory process noted above, this case will undoubtedly establish a new framework for utility regulation in Colorado. Therefore, we intend to be very aggressive in proposing regulatory principles which will minimize or eliminate regulatory lag in adjusting our prices. We also will be requesting the use of regulatory incentives that will move us away from the traditional cost-plus approach to one of sharing in cost reductions and improvements in productivity, so that both customers and shareholders benefit.

Also, given the renewed emphasis on conservation and demand-side resources, we will propose incentives which allow us to be an active and willing participant in these energy efficiency efforts. We already have started down this path by initiating a collaborative process to address energy efficiency issues. Based on the positive working relationship that we have developed with our commission and the other participants in the regulatory process, I believe we will achieve our objectives in the regulatory arena.



As has always been the case, the most important ingredient for our future success is our people, and 1991 was a very demanding and difficult year for the employees of Public Service Company. At mid-year, we realized that the unexpected costs for defueling delays at Fort St. Vrain and the requirement to enter into a rate settlement agreement had the potential to cause a significant decrease in 1991 earnings. I asked our employees to step up to this challenge by reducing expenses to cover the forecasted shortfall in earnings. They met my expectations and also committed to continue this effort in 1992 and beyond.

Through our service excellence program, our employees also made a significant number of other contributions to enhance our ability to reach our earnings goal. These included several employee-directed teams, which addressed subjects ranging from labor-management communication and problem solving to performance-based incentive plans.

I believe it is clear that in 1991 we developed a discipline for achieving positive results in the face of difficult circumstances. With that discipline and the continuing efforts of our management team and employees, I am confident we can reach our objective of being the premier energy company in the Rocky Mountain region.

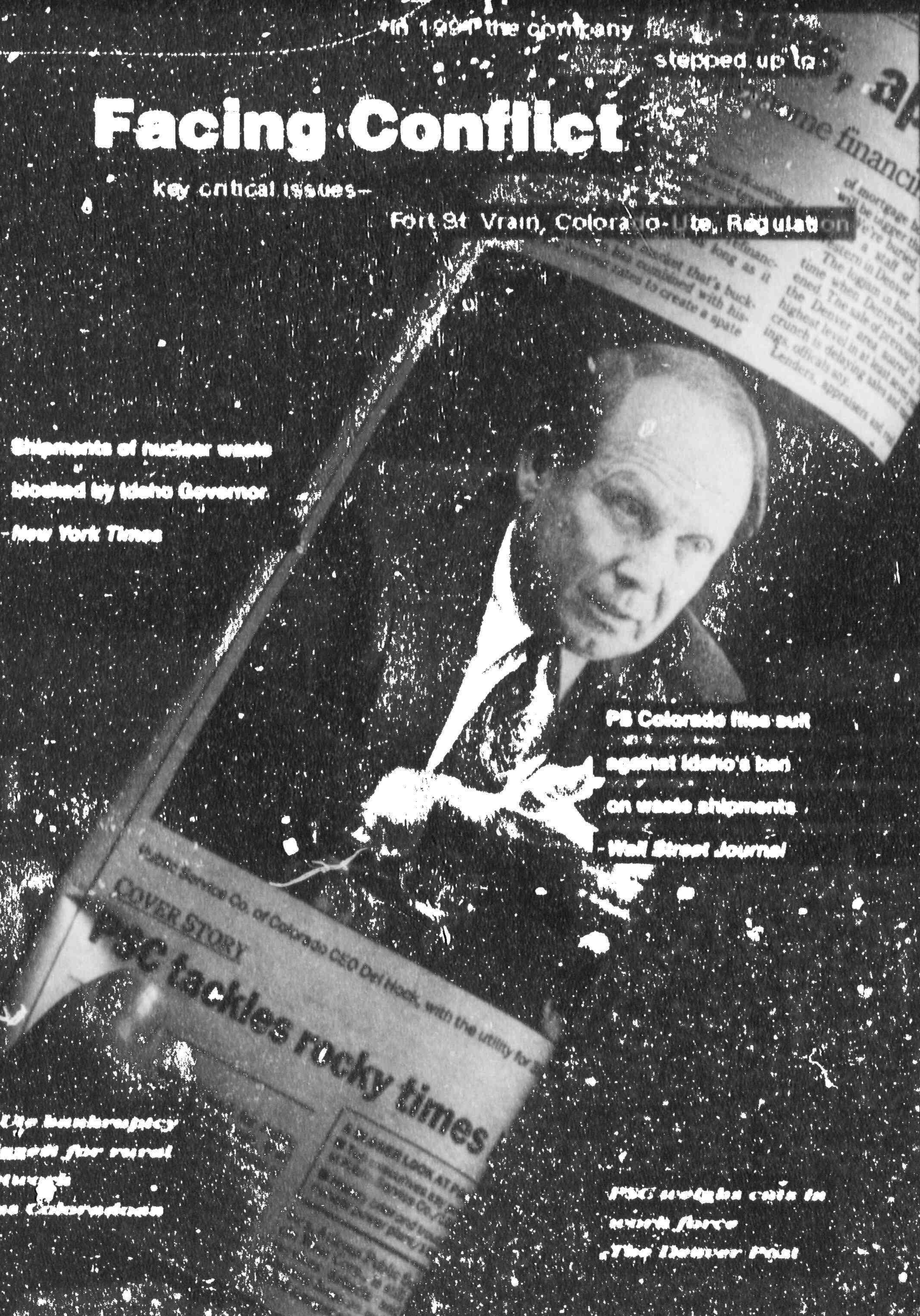
D.D. Hock
Chairman, President and Chief Executive Officer
Public Service Company of Colorado

In 1991 the company stepped up to

Facing Conflict

key critical issues—

Fort St. Vrain, Colorado-Ute, Regulation



Shipments of nuclear waste blocked by Idaho Governor
-New York Times

PS Colorado files suit against Idaho's ban on waste shipments
-Wall Street Journal

Colorado-Ute bankruptcy filing is biggest for rural electric network
-Fort Collins Coloradoan

PSC weighs cuts in work force
-The Denver Post

Lower electric rates urged
-Rocky Mountain News

Even a casual consumer of Colorado business news would have been aware of the many conflicts that confronted Public Service Co. of Colorado during 1991. Topping the list of familiar issues were Public Service Co.'s efforts to resolve its decommissioning-related problems at the idled Fort St. Vrain nuclear generating station. Secondly, much local and national news was generated concerning Public Service Co.'s role in the resolution of the bankruptcy of the Colorado-Ute Electric Association. Another major controversy that spawned much public and investment community debate was how the company would respond to pressure from consumer groups and the Colorado Public Utilities Commission staff to refund substantial earnings to its customers and dramatically lower future rates. Because of the company's ability to face these conflicts, to develop and negotiate resolutions, and to answer these and many other issues, 1991 will be recognized as a year of "getting results."

Building upon this momentum for 1992 was the development of a strategic plan by the company's senior executives to clearly define the parameters of the company's business and focus on a direction of targeted growth. During the evolution of this strategy, three key objectives emerged that effectively set that direction.

- Public Service Co. will strive to improve the total return to shareholders, with an emphasis on growing book value and maintaining a capital structure that will improve credit quality.
- Public Service Co. will focus on the core electric and natural gas businesses.
- Public Service Co. will meet the needs of the marketplace and develop core business services that assure customer retention and growth.

Creating the productive internal environment needed to realize these objectives demonstrated the company's commitment to its shareholders and customers. This strategic concentration, coupled with the company's willingness to step up to current and future issues, will be the driving force as Public Service Co. aggressively positions itself to maximize future earnings opportunities.

Resolving Fort St. Vrain

Public Service Co. made considerable progress during 1991 to address the lingering problems associated with the Fort St. Vrain nuclear generating station. To say that the plant has been a "challenge" to the company is an understatement.

Fort St. Vrain had been the nation's only high-temperature, gas-cooled commercial nuclear reactor. It began commercial operation in 1979 and successfully demonstrated a safer, more efficient technology. However, the plant's continuing financial drain on the company– coupled with the need to make additional repairs– caused Public Service Co. to permanently halt plant operations in August 1989.

Since that time, the company has been aggressively attempting to remove and properly store the plant's nuclear fuel, which is required before the decommissioning process can continue. Although three of nine spent fuel segments already were stored at the Department of Energy's (DOE) Idaho National Engineering Laboratory under the terms of a 1965 agreement with the DOE, the company's efforts to ship the remaining six segments during 1991 were met with strong opposition from the state of Idaho. Considerable litigation– involving the DOE, Public Service Co., the Shoshone Bannock Indian Tribes and the state of Idaho– ensued.

While Public Service Co. and the DOE initially received favorable rulings in both the U.S. District Court in Boise, Idaho and the 9th Circuit Court of Appeals in San Francisco, Idaho has been successful in temporarily blocking the shipments by persuading the Idaho federal court that DOE must obtain a state air quality permit for its Idaho facility before more spent fuel can be stored there.

It was imperative that this situation be addressed, because each additional month the fuel remained in the reactor core Public Service Co. had been incurring approximately $2.5 million in additional costs to maintain plant systems and retain essential personnel. Because the company realized it could not rely solely on a successful legal outcome, it built a facility at the plant site for the interim storage of the spent fuel.

Public Service Co.'s management recognized the obstacles in its course and established a philosophy, system and action plan to meet them head-on

The licensed structure indeed proved necessary, and Public Service Co. began removing the fuel from the plant's core and storing it at the temporary facility in December 1991. It is estimated that the fuel will be completely removed from the plant by August 1992, after which decommissioning can continue.

Meanwhile, Public Service Co. and the DOE are continuing in their efforts to overcome the legal barriers necessary to ship the fuel to the Idaho National Engineering Laboratory, which has a facility specifically designed to store it. The spent fuel from Fort St. Vrain contains the energy equivalent of more than 14 million barrels of oil, and its chances of being reprocessed are much greater if it is sent to Idaho, rather than being temporarily stored at Fort St. Vrain and eventually shipped to a final repository. Storing the used fuel at Fort St. Vrain beyond 1995 has the potential for further financial impact on the company. In addition, Public Service Co. is continuing to evaluate its ability to recover shipping delay costs from the DOE or the state of Idaho.

The other major issue that Public Service Co. had to address was whether to pursue the option of dismantling and decommissioning Fort St. Vrain on a three-year basis, or the alternative of postponing the decommissioning process up to 55 years. The advantage of the short-term approach is that it eliminates future financial, regulatory and environmental uncertainties that would exist if this work were deferred until the middle of the 21st century.

However, moving ahead with the three-year plan presented a new obstacle– an additional $124 million was needed to fund the early dismantlement procedure. After frustrated attempts to expeditiously resolve this issue through the normal regulatory process, Public Service Co. initiated discussions directly with the Office of Consumer Counsel, the staff of the Colorado Public Utilities Commission and other interested parties. The discussions were successful, and on December 27, 1991, the commission approved a settlement agreement that will allow the recovery of the $124 million during a 12-year period, beginning July 1993. As part of that settlement, Public Service Co. agreed to not pursue certain rate-making principles and to make annual contributions to the Colorado Energy Assistance Foundation over that same time period.

As a result of securing this additional funding for the short-term decommissioning process and successfully having a place to store the plant's spent fuel, the company has put the most difficult Fort St. Vrain issues behind it. It can now look ahead with confidence to its plans to repower the plant as a natural gas-fired facility by 1998.

Finding Success in a Changing Regulatory Arena

An effort by a Colorado consumer group and the staff of the Colorado Public Utilities Commission to significantly lower Public Service Co. rates and provide customer refunds was the cause of considerable concern to the company early in 1991. Again, Public Service Co. demonstrated that it could face conflict and minimize the adverse results.

In response to a formal complaint by the Office of Consumer Counsel and a resulting agreement, Public Service Co. filed its first rate case since 1983. In this January 31 filing, the company requested a nominal $13.4 million rate increase.

After reviewing the rate filing, the staff of the utility commission and the consumer group both filed testimony arguing that Public Service Co. should *reduce* its rates more than $100 million annually. In addition, the Office of Consumer Counsel sought a refund that totaled nearly $167 million. Rather than proceed through the lengthy and unpredictable regulatory process, Public Service Co. successfully negotiated a much more favorable settlement, which was approved by the Colorado Public Utilities Commission in July 1991.

Under the terms of the agreement, the company agreed to a $22 million customer refund in 1991 and an electric rate reduction of approximately $3 million per month from January 1992 through June 1993. The financial impact of the settlement was significantly less than the recommended refund and rate reductions and was in the best interest of Public Service Co.'s investor constituents. The company also agreed to file a rate case late in 1992, with new rates anticipated to become effective by July 1993.

This rate case filing– coupled with an agreement to address specific energy conservation proposals– will be a principal corporate focus in 1992. As the largest energy company in Colorado, the company realizes it must take a leadership and cooperative role in working with state regulators and others to develop better, more future-oriented regulatory processes.

Specifically, the company has agreed to explore novel ways to implement various demand-side management programs– measures directed at reducing the growth of peak demand for electricity– that benefit both customers and the company. Also being reviewed is the traditional relationship that exists between revenues and customer sales that inhibits energy conservation.

Public Service Co. also agreed to establish a collaborative program to analyze how the company should invest in customer incentives to trim electricity demands. Another commitment involves

The issue of what to do with Fort St. Vrain's fuel has been addressed, and the company will receive $124 million through rates to pay for the additional early decommissioning costs.

Public Service Co. demonstrated that

it could face conflict

Taking Action

and minimize

the adverse results

Colorado utility fights back,

asks court to okay N-waste

shipment

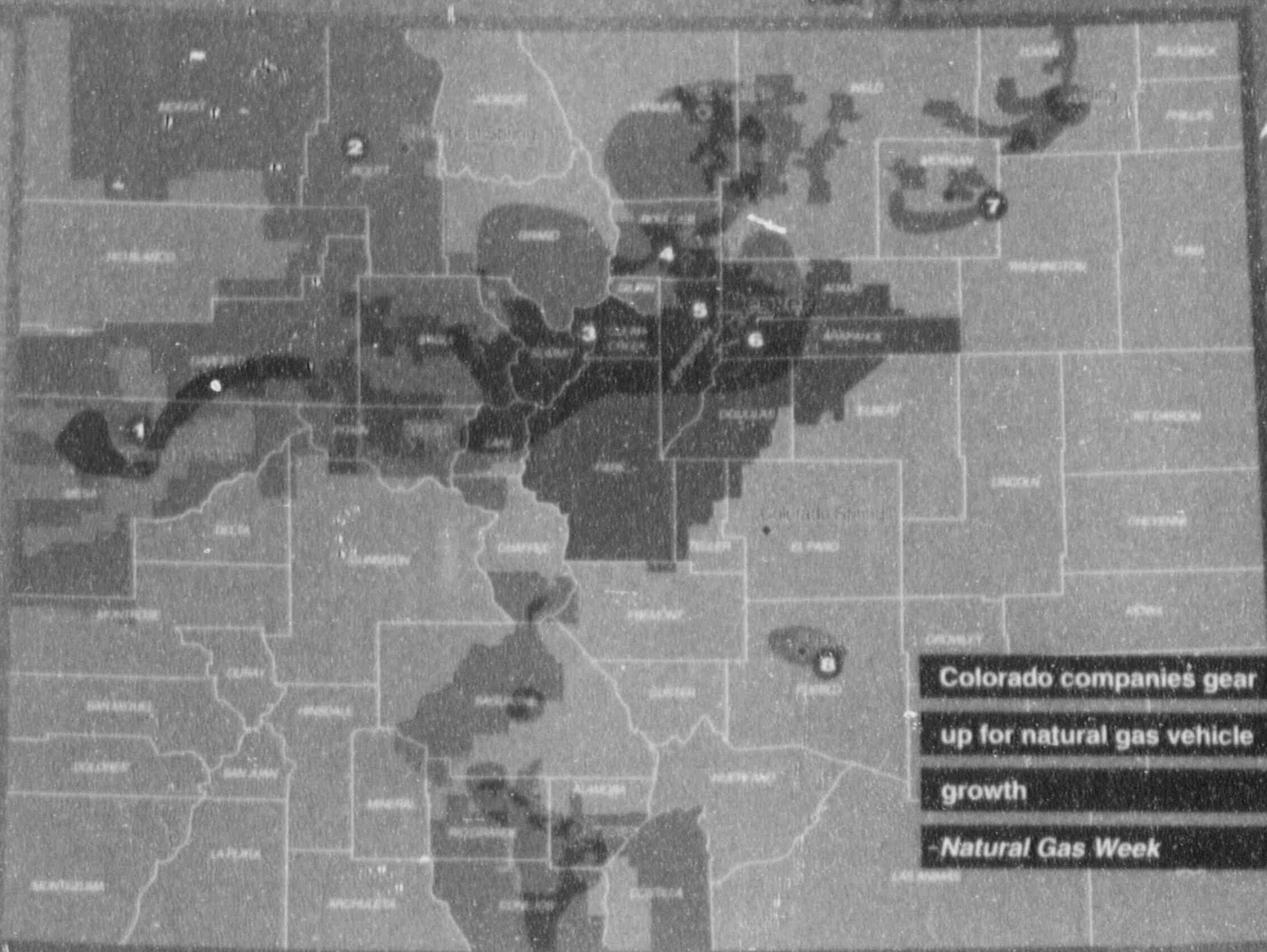
–Energy Daily

[illegible]

The acquisition one of the nation's largest bankruptcies will solve

Answering Issues

and successfully meet the needs of dozens of separate interests



Colorado companies gear up for natural gas vehicle growth

-Natural Gas Week

Key

- PSCo Electrical Service Territory
- PSCo Natural Gas Service Territory
- Grand Valley Rural Power Lines
- Yampa Valley Electric Association
- Intermountain Rural Electric Association
- Holy Cross Electric Association

1. Cameo Steam-Electric Plant
2. Hayden Steam-Electric Plant
3. Cabin Creek Hydroelectric Plant
4. Valmont Steam-Electric Plant
5. Leyden Underground Natural Gas Storage Facility
6. Denver Steam-Electric Plants - Cherokee, Zuni, Arapahoe
7. Pawnee Steam-Electric Plant
8. Comanche Steam-Electric Plant

** While this map closely approximates the service areas represented, it is not intended to be accurate in every detail.*

investigating ways to include a variety of groups in Public Service Co.'s plans to meet the future energy needs of its customers. And finally, the company pledged to address how it could assist low-income consumers to lower their personal energy usage and resulting utility bills.

These issues are garnering considerable attention, and the Colorado Public Utilities Commission has been actively involved in discussing these matters at the national level. Public Service Co. believes the commission is approaching them in a constructive manner that will lead to realistic and beneficial conclusions.

It is apparent that the regulatory process is changing, and Public Service Co. is positioning itself to find new opportunities as its business changes. Both the company and the communities it serves will benefit as it implements programs that allow a wiser, more productive use of what is a finite source of energy.

Colorado-Ute Acquisition: A Successful Conclusion for Public Service Co.

The billion dollar bankruptcy of the Colorado-Ute Electric Association passed a milestone on February 19, 1992, when the U.S. Bankruptcy Court in Denver confirmed a consensual plan of reorganization filed by Public Service Co., Denver-based Tri-State Generation and Transmission Association, and PacifiCorp, based in Portland, Oregon.

Public Service Co.'s involvement in the solution of the Colorado-Ute bankruptcy will be rewarded with substantial strategic and financial benefits.

This long-awaited decision was the culmination of more than two and a half years of strategic planning, intense negotiations between consumer-owned and investor-owned power interests, considerable political and customer debate and extensive communications with many different groups. The three-way plan represents a landmark agreement that addresses the concerns and interests of all the involved parties, while assuring rural Colorado consumers of reliable, long-term power supplies at reasonable and stable prices.

The reorganization plan—which also has been approved by the Colorado Public Utilities Commission—still requires the approval of the Federal Energy Regulatory Commission. When finalized, it will solve one of the nation's largest bankruptcies and successfully meet the needs of dozens of separate interests. But more importantly to Public Service Co., it represents substantial strategic and financial benefits to its shareholders and customers.

In general, the plan divides the assets of Colorado-Ute among the three utilities. Those assets include three large coal-fired power plants, five small coal-fired or hydroelectric facilities and more than 1,800 miles of transmission lines. Public Service Co. will acquire 332 megawatts of the 1,083 megawatts owned or leased by Colorado-Ute and operate the 446-megawatt Hayden power plant. It also will acquire about 900 miles of transmission lines and related facilities.

Colorado-Ute's electric market, consisting of approximately 200,000 Colorado customers served by 14 rural electrification associations, also will be divided under the terms of the reorganization plan. Four of the cooperatives, which represent approximately half of Colorado-Ute's electric load, will be served by Public Service Co. The 10 remaining smaller cooperatives will become members of Tri-State.

Public Service Co. is optimistic that the reorganization plan will be approved by the Federal Energy Regulatory Commission in March and the transaction can be closed in April.

The myriad benefits of this acquisition to Public Service Co. and its shareholders include:

Market Growth—Public Service Co. will provide wholesale power to the four member-cooperatives that are located in the highest growth areas in Colorado. Many of these areas—primarily situated to the south and east of metropolitan Denver and in developing mountain communities and ski resort areas—are experiencing growth rates twice as high as the projected levels for most of Public Service Co.'s service territory.

Improved Earnings Potential—With additional plant investment in its regulated rate base, there will be a favorable impact on the company's earnings level.

Low-Cost Assets for Future Needs–Acquiring these assets provides the company with new capacity at a fraction of the cost associated with new plant construction (approximately $350 per kilowatt, compared to $1,200 to $1,500 per kilowatt). Also, Public Service Co. will contract for 200 megawatts of purchased power that will provide extra time to re-power Fort St. Vrain and delay the need to construct the next generating unit until sometime after 2000.

Reduction in Purchased Power Requirements–The company is working to reduce its dependence on purchased power, and this acquisition will replace some existing purchased power contracts. It is anticipated that the company's purchased power component will drop from nearly 39 percent to approximately 36 percent of its total power supply.

Improved Load Balance–Public Service Co.–which has its greatest energy demand during the summer air-conditioning months–will achieve greater system efficiency through the addition of new winter-peaking wholesale customers.

Additional Transmission Options–As a result of the three-way deal, the company will become joint owner in bulk power transmission lines to the southwest and southeast, which will enhance the company's flexibility to negotiate future electricity sales or purchases. This additional transmission capacity also blends well with Public Service Co.'s progressive approach to make its excess transmission accessible to outside users. As a result, the company's transmission system will continue to be available to any agency or company wanting to send power to a wholesale customer.

Added Investment Value

The hard-won successes of 1991 will unquestionably generate the momentum necessary to continue the company's efforts to optimize the return to its shareholders.

The headway made on the various critical issues during the year has garnered favorable reaction in the investment markets. Although lower interest rates positively impacted most utility stocks, Public Service Co.'s ability to resolve the financial risk associated with these issues has led to strengthening the market's perception of the company's investment potential.

in relation to the changing regulatory environment, balancing the interests of all our constituents is critical.

This is evidenced by the steady upward movement in the market value of the company's common stock, which closed at a 52-week high of $27.00 per share on December 31, 1991.

Maintaining the dividend level since 1986, in light of the considerable financial strain applied by Fort St. Vrain, illustrates the strength of the company's continuing commitment to its shareholders. Public Service Co. is hopeful that it not only can sustain the dividend, but that it has the strategies in place to build its financial strength to the point where a dividend increase can be considered.

A principal component of the company's drive toward future financial growth was a successful company-wide effort to reduce expenses. In response to the June 1991 settlement agreement, the company recognized the need for a significant reduction in operating and maintenance expenses to sustain an earnings position able to support the commitment to investor value.

With the extraordinary commitment of its work force, the company was successful in reducing expenses for the balance of the year by more than $17 million. A similarly aggressive goal has been set for 1992 to maintain expenses at the reduced 1991 level.

A second strategic objective–contributing to the company's ability to position for future growth–relates to the decision to concentrate on core business activities and structure each organization to allow for more efficient operations. To support this endeavor, a strategy was implemented to assess every function performed in the company and define those essential to the core business. This has led to some very difficult decisions, including some necessary reductions in the work force. Although this process has been and will continue to be a demanding one, significant progress has been made.

It is clear that 1991 was a year that Public Service Co. aggressively stepped up to the "problem issues" and enjoyed great success in moving them dramatically toward resolution. These accomplishments tie directly to the three corporate objectives, described earlier, which were developed by the company's Executive Policy and Strategy Group–improving total return to shareholders, focusing on the core electric and natural gas businesses and better meeting the needs of the marketplace.

Although some of the critical issues are now behind Public Service Co., the momentum created in 1991 must continue in 1992 and beyond. The company's commitment to its shareholders, customers and employees remains central to its future success.

The headway made

on the various critical issues

Optimizing Return

during the year

in the investment markets

has garnered favorable reaction

Company stock closes 1991 at a 52-week high of $27.00, up from 1990 close of $23.25

We expect that the results of management's cost cutting measures and strategy to increase operating capacity through acquisitions will have a positive effect on operating earnings in 1992 and 1993

—Hanifen, Imhoff Inc.

Public Service Co. will maximize its resources and experience in the core natural gas business and be responsive to the market demand for clean fuels.

Other Key Issues

Natural Gas Business: Experiencing Results

Public Service Co. continues to be ideally positioned to maximize its experience and resources in the core natural gas business. Not only will the traditional natural gas supply business remain strong, but also the company's WestGas subsidiary is experiencing dramatic gains in its effort to build the infrastructure to move Rocky Mountain region natural gas to the growing demand of the California and Midwest markets.

The company also anticipates that shareholders will benefit from its response to the market demand for clean fuels. Such ventures as Natural Fuels, with a mission to increase the demand for compressed natural gas, will result in increased corporate good will, as well as benefits to the company's bottom line. The company is already seeing favorable results from its efforts to encourage residential customers to convert their wood-burning fireplaces to clean-burning natural gas.

The long-term success of the company's natural gas business, however, will be dependent on how well it responds to the changing regulatory environment. Later in 1992, it is anticipated that the Federal Energy Regulatory Commission will issue a final decision on its Notice of Proposed Rulemaking, which seeks to complete the restructuring of the natural gas industry. Public Service Co. intends to quickly and actively respond to the anticipated changes and beneficially utilize the increased options to better manage its gas supply.

Environment: A Continuing Focus

1991 was another year filled with environmental plaudits for Public Service Co. It continues to be recognized as an environmental leader in Colorado, best known for its clean air efforts. These and other activities include developing the infrastructure to allow for the operation of natural gas fueled vehicles, hosting two Department of Energy Clean Coal Technology demonstration projects, helping to establish Colorado's Pollution Prevention Partnership, using fewer harmful solvents in its operations and recycling ozone-damaging Freon™.

Of equal interest to its investors is how the company will be impacted by the new federal standards established by the Clean Air Act Amendments of 1990. Because of the company's early commitment in this area and the use of low-sulfur western coal, Public Service Co. already meets the strict standards for sulfur dioxide emissions. In addition, the company is working to meet the nitrogen oxide emissions requirement by 2000, in conjunction with a similar commitment it made to the governor of Colorado in 1989.

Management Changes

During its January 28, 1992, board of directors meeting, Philip D. Shaffer was named vice president of division customer operations, responsible for all customer operations outside of the Denver metropolitan area. He will continue in his role as president of the Cheyenne Light, Fuel and Power Co. subsidiary.

In addition, a variety of responsibility changes were made among the company's executive officers. Marilyn E. Taylor, vice president of human resources, assumed additional responsibilities for public affairs and corporate services and became vice president of administrative services. Richard C. Kelly, who was assigned senior executive responsibility for this area, was named senior vice president, finance and administration, and continues as chief financial officer.

Other related changes included assigning James R. McCotter senior executive responsibility for the rates and regulations function and appointing Ross C. King as vice president of metropolitan customer operations, which includes executive responsibility for the gas and electric distribution divisions.

1991 Financial Information

OPERATING STATISTICS

Public Service Company of Colorado and Subsidiaries

Natural Gas Service Statistics

	1991	1990	1989	1988	1987	1986	1981
Bcf Gas Deliveries	**232.7**	210.9	202.2	194.5	179.3	176.3	176.1
% Change	**10.3%**	4.3	4.0	8.5	1.7	(7.9)	(13.4)%
Customers (000)	**878.6**	865.4	853.1	841.4	832.0	819.7	701.8
% Change	**1.5%**	1.4	1.4	1.1	1.5	3.2	3.0%
Average Annual Residential Mcf Usage	**116.8**	112.0	112.7	116.3	109.5	105.6	112.9
% Change	**4.3%**	(0.6)	(3.1)	6.2	3.7	(12.3)	(19.4)%
Annual Heating Degree Days	**5,914**	5,575	5,819	5,968	5,436	5,321	4,570
% Change	**6.1%**	(4.0)	(2.5)	9.8	2.2	(16.4)	(20.8)%
Average Residential Revenue Per Mcf	**$3.74**	3.78	3.81	3.82	3.88	4.13	$3.48
% Change	**(1.1)%**	(0.8)	(0.3)	(1.5)	(6.1)	(1.4)	(28.9)%
Average Annual Revenue Per Residential Customer	**$437**	420	430	441	425	436	$393
% Change	**4.0%**	(2.3)	(2.5)	3.8	(2.5)	(18.7)	3.9%
Daily Availability-(MMcf)	**1,601**	1,575	1,595	1,517	1,471	1,461	1,457
Maximum Peak-Day Sendout (MMcf)	**1,258**	1,575	1,497	1,170	1,094	1,080	1,279
% Change	**(20.1)%**	5.2	27.9	6.9	1.3	(14.1)	2.6%

Electric Service Statistics

	1991	1990	1989	1988	1987	1986	1981
Kilowatt-Hour Sales (millions)	**20,452**	20,148	19,716	19,194	18,357	17,926	15,473
% Change	**1.5%**	2.2	2.7	4.6	2.4	2.2	1.8%
Customers (000)	**1,000.7**	990.8	983.6	974.[illegible]	967.1	958.0	846.1
% Change	**1.0%**	0.7	1.0	0.7	0.9	1.8	3.1%
Average Annual Residential Kwh Usage	**6,563**	6,445	6,348	6,403	6,250	6,152	5,734
% Change	**1.8%**	1.5	(0.9)	2.3	1.7	(1.3)	(3.4)%
Average Residential Revenue Per Kwh	**7.07¢**	7.02	7.11	7.18	7.18	7.33	5.74¢
% Change	**0.7%**	(1.3)	(1.0)	-	(2.0)	2.7	12.1%
Average Annual Revenue Per Residential Customer	**$464**	453	451	460	449	451	$329
% Change	**2.4%**	0.4	(2.0)	2.5	(0.4)	1.3	8.2%
Net Dependable System Capability at Time of Peak-Megawatts	**4,168(s)**	4,327(w)	3,912(s)	3,911(s)	3,672(s)	3,641(s)	3,110(s)
Net Firm System Peak Load (Mw)	**3,568**	3,589	3,484	3,362	3,298	3,237	2,820
% Change	**(0.6)%**	3.0	3.6	1.9	1.9	7.0	1.6%
Reserve Margin at Time of Peak	**16.8%**	20.6	12.3	16.3	11.3	12.5	10.5%
Generation by Class of Fuel:							
Coal	**98.1%**	98.3	92.9	91.1	94.6	98.1	85.3%
Natural Gas	**1.7%**	1.6	2.9	3.5	3.8	1.3	8.4%
Oil	**0.2%**	0.1	0.2	0.1	0.1	0.1	0.3%
Nuclear	**-**	-	4.0	5.3	1.5	0.5	6.0%
Average Cost Per Unit of Fuel:							
Coal-Ton	**$22.40**	21.44	21.41	22.30	25.05	24.18	$21.84
Natural Gas-Mcf	**$ 1.98**	2.07	2.16	2.27	2.19	2.84	$ 3.12
Oil-Barrel	**$27.16**	27.85	30.31	28.65	22.82	24.93	$30.96
Average Fuel Cost Per MMBTU	**$ 1.20**	1.17	1.17	1.25	1.34	1.30	$ 1.22

(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)

	1991	1990	1989	1988	1987	1986	1981
Operating Revenues:							
Electric	$1,180.5	1,145.9	1,139.5	1,116.0	1,075.8	1,045.6	$ 742.1
Gas	587.6	561.7	577.3	591.4	563.3	596.6	582.4
Other	26.[illegible]	26.3	23.9	23.0	18.3	15.7	11.6
Total Revenues	$1,794.5	1,733.9	1,740.7	1,730.4	1,657.4	1,657.9	$1,336.1
Income Before Extraordinary Item and Cumulative Effect of a Change in Accounting Method	$ 149.7	146.1	148.8	125.0	143.7	123.8	$ 100.8
Extraordinary Item	–	–	–	–	–	(101.4)	–
Cumulative Effect to 1/1/87 of Accruing Unbilled Revenues	–	–	–	–	29.6	–	–
Net Income	149.7	146.1	148.8	125.0	173.3	22.4	100.8
Preferred Dividend Requirements	12.2	12.4	12.6	12.8	13.2	15.7	16.7
Earnings Available for Common Stock	$ 137.5	133.7	136.2	112.2	160.1	6.7	$ 84.1
Earnings Per Weighted Average Share:							
Before extraordinary item and cumulative effect of a change in accounting method	$2.48	2.49	2.59	2.14	2.49	2.06	$1.97
Extraordinary item	–	–	–	–	–	(1.93)	–
Cumulative effect to 1/1/87 of accruing unbilled revenues	–	–	–	–	0.56	–	–
Total	$2.48	2.49	2.59	2.14	3.05	0.13	$1.97
Dividends Per Share:							
Paid	$2.00	2.00	2.00	2.00	2.00	2.00	$1.66
Declared	$2.00	2.00	2.00	2.00	2.00	2.00	$1.58
Common Stock Outstanding:							
Weighted average (000)	55,471	53,626	52,559	52,457	52,414	52,349	42,728
Year-end (000)	56,294	54,320	52,807	52,458	52,457	52,369	44,896
Total Assets	$3,473	3,243	3,054	2,995	2,945	2,929	$2,422
Common Equity	$1,034	964	905	865	858	801	$ 735
Preferred Stock:							
Subject to mandatory redemption at par	44	46	49	52	54	67	89
Not subject to mandatory redemption	140	140	140	140	140	140	140
Long-Term Debt	900	896	913	944	920	846	866
Short-Term Borrowings*	297	259	186	162	196	191	64
Total Capitalization	$2,415	2,305	2,193	2,163	2,168	2,045	$1,895
Capitalization Ratios–Year-End:							
Common equity	42.8%	41.8	41.2	40.0	39.6	39.2	38.9%
Preferred stock (incl. due within 1 yr.)	7.7%	8.2	8.6	8.9	9.0	10.1	12.1%
Long-term debt (incl. due within 1 yr.)	41.2%	40.7	41.7	43.6	42.4	41.4	45.8%
Notes payable and commercial paper	8.3%	9.3	8.5	7.5	9.0	9.3	3.2%
Construction Expenditures	$260.7	261.2	174.4	162.8	127.6	[illegible]	$256.7
% of Total capitalization	10.8%	11.3	8.0	7.5	5.9	9.6	13.5%
Cash Generated Internally**	$177.7	174.6	172.3	192.8	47.9	130.6	$106.7
% of Construction expenditures***	69.4%	67.7	99.7	118.8	38.0	67.1	46.8%
Rates of Return Earned:							
Total capitalization (Oper. income)	10.1%	10.3	11.3	10.2	10.7	11.7	7.8%
Avg. common equity before extraordinary item and a change in accounting method (Net to common)	13.0%	14.3	15.4	13.0	15.7	12.7	12.1%
Avg. common equity (Net to common)	13.8%	14.3	15.4	13.0	19.3	0.8	12.1%
Pretax Coverage of Interest Expense	2.94x	3.07	3.02	2.81	3.31	2.52	3.24x
Effective Income Tax Rate	32%	34	31	33	46	33****	40%
Payout Ratio on Dividends Paid	80.6%	80.3	77.2	93.5	65.6	1,538.5	84.3%
Book Value Per Share	$18.38	17.74	17.13	16.49	16.35	15.29	$16.39
Number of Employees–Year-End	6,565	6,611	6,636	6,559	6,476	6,503	6,424

* 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. 1981 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. 1981 calculated as funds generated internally as a % of net construction expenditures.

**** Before extraordinary item.

Results of Operations

Earnings per share were $2.48, $2.49 and $2.59 in 1991, 1990 and 1989, respectively. The 1991 earnings remained relatively stable, when compared to 1990, despite significant factors including the negative impact of a $22 million ($13.8 million after-tax or 25 cents per share) refund to electric customers resulting from the rate Settlement Agreement approved by The Public Utilities Commission of the State of Colorado (CPUC) (see Note 7, Commitments and Contingencies in the Notes to Consolidated Financial Statements). This negative factor was generally mitigated by the positive effects of higher 1991 electric sales and natural gas deliveries as well as rate and tax adjustments which are discussed below. The 1990 earnings, when compared to 1989, declined primarily due to general increases in the cost of labor, materials and supplies. The 1990 earnings, however, were positively affected by the exclusion of nuclear operating and maintenance costs which have been charged against the defueling and decommissioning liability since August 1989 (see Note 2, Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements).

Revenues

The increase in 1991 electric operating revenues, when compared to 1990, is due, in part, to a 1.5% increase in electric sales volume resulting from a 1.0% increase in customers and weather related factors. In addition, the positive effect of revisions in the negotiated electric retail base rate reductions and higher energy costs, which are recovered from customers through the Electric Cost Adjustment (ECA), served to further increase electric operating revenues. As discussed in greater detail in Note 7, Commitments and Contingencies in the Notes to Consolidated Financial Statements, base rate reductions amounted to approximately $14.9 million, $24 million, and $36 million in 1991, 1990 and 1989, respectively. The 1991 electric rate reduction, which is offset by a similar positive gas rate adjustment, was instituted to rectify the earnings imbalance which exists between the electric and gas departments. These positive factors, however, were offset by a $22 million electric refund recognized in the second quarter of 1991. The refund was the result of a rate Settlement Agreement entered into with the Colorado Office of Consumer Counsel (OCC) and approved by the CPUC. The moderate increase in 1990 electric revenues over 1989 is primarily attributable to a 2.2% increase in sales volume and the revisions in the negotiated electric retail base rate reductions which were offset, in part, by lower energy costs recovered through the ECA.

Gas operating revenues increased significantly in 1991, when compared to 1990, due to the positive effect of the gas rate adjustment designed to rectify the departmental earnings imbalance (see Note 7, Commitments and Contingencies in the Notes to Consolidated Financial Statements) and a 4.2% increase in gas sales (which exclude transportation services and gathering and processing activities). The higher sales resulted primarily from colder weather experienced in 1991 as well as a 1.5% increase in customers. These increases, however, were offset by a lower recovery of gas costs, which are passed on to customers through the Gas Cost Adjustment (GCA). Total gas deliveries increased 10.3% and 4.3% in 1991 and 1990, respectively, due to increases in gas gathering and processing activities and transportation services. The per unit fee charged for transportation services, while significantly less than the per unit amount charged for a sale to a similar customer, provides an operating margin 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 increases in deliveries from the sale of gas. Lower gas costs from suppliers in 1990, when compared to 1989, which are passed on to customers through the GCA, and a 1.3% decrease in gas sales were the primary reasons for the decline in 1990 gas revenues.

Electric and gas operating revenues reflect the effect of rate changes and cost adjustment clauses on prices of units sold. Operating revenues also reflect the volume changes in unit sales and deliveries. The foregoing factors all contributed to annual changes in revenues when compared to revenues for the preceding years as indicated in the following table.

	(Millions of Dollars) 1991	1990
Electric revenues		
Base rate changes	**$ 8.3**	$ 13.3
Electric cost adjustment	**27.4**	(26.3)
Electric refund	**(22.0)**	–
Sales volume and other changes	**20.9**	19.4
Net increase	**$ 34.6**	$ 6.4
Gas revenues		
Base rate changes	**$ 14.2**	$ –
Gas cost adjustment	**(13.7)**	(10.6)
Deliveries volume and other changes	**25.4**	(5.0)
Net increase (decrease)	**$ 25.9**	$ (15.6)

Operating Expenses

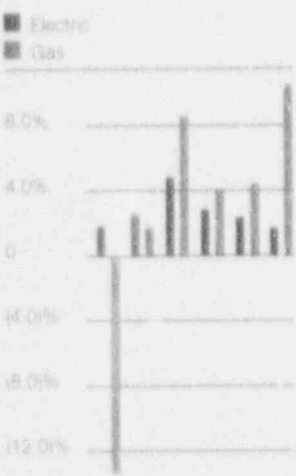
The increases (decreases) in operating expenses from the preceding year were as follows:

	(Millions of Dollars) 1991	1990
Fuel used in generation	**$ 10.6**	$ 1.0
Purchased power	**21.9**	6.9
Gas purchased for resale	**7.7**	(21.8)
Other operating expenses	**29.1**	2.5
Maintenance	**(18.3)**	(1.2)
Depreciation	**5.2**	3.7
Taxes (other than income taxes)	**4.3**	2.6
Income taxes	**(4.7)**	7.4
Net increase	**$ 55.8**	$ 1.1

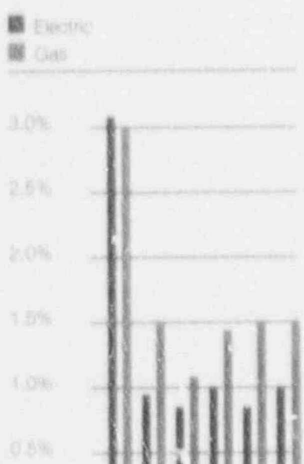
The 1991 increase in fuel used in generation expense is primarily attributable to higher fuel expense adjustments which correlate with the increase in electric operating revenues associated with the ECA. Slight increases in the per unit cost of coal and moderate increases in generation in both 1991 and 1990 served to increase fuel used in generation expense when compared to the respective preceding year. The 1990 increases, when compared to 1989, were mitigated by lower fuel expense adjustments associated with the ECA.

Purchased power expense increased significantly in 1991, when compared to 1990, due in part, to higher per unit costs for the energy purchased and increased Kwh purchases. These increases were further impacted by increased purchased power expense adjustments which correlate to the increased electric operating revenues associated with the ECA. In addition, the Company continues to purchase an increasing amount of energy from Qualifying Facilities (QFs) due to regulatory requirements. The QFs charge a higher rate per Kwh than the Company's other suppliers. The increased purchased power expense in 1990 over 1989 was primarily attributable to increased Kwh purchases which were minimized by decreased purchased power expense adjustments.

SALES GROWTH—
ELECTRIC AND GAS



CUSTOMER GROWTH—
ELECTRIC AND GAS



The increase in gas purchased for resale expense was primarily attributable to an increase in sales during 1991 when compared to 1990. Gas purchased for resale expense was lower in 1990, when compared to 1989, due to lower gas sales and a decline in the per unit cost of gas.

The increase in other operating expenses is due, in part, to the recognition in the first quarter of 1991 of $1[illegible].1 million in additional defueling and decommissioning expenses related to actual and anticipated Fort St. Vrain spent fuel shipping delays (see Note 2, Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements). In addition, higher administrative and general expenses and higher customer expenses contributed to the increase in other operating expenses in 1991 and 1990 when compared to the respective preceding year.

Lower levels of scheduled plant maintenance throughout 1991, when compared to 1990, was the primary reason for the decline in maintenance expenses in 1991. In addition, approximately $8.2 million of impairment primarily associated with nuclear inventory was recognized in 1990 for which there was no corresponding charge in 1991. The decline in 1990 maintenance expenses, when compared to 1989, is due primarily to the exclusion of nuclear maintenance expenses which have been charged against the defueling and decommissioning liability since the cessation of operations in August 1989.

The slight increase in 1991 and 1990 depreciation expense, when compared to the respective preceding year, is primarily attributable to ongoing plant additions.

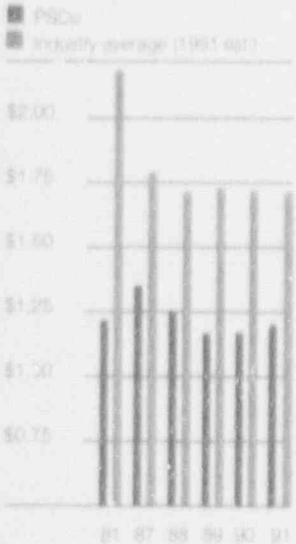
Taxes other than income taxes increased in 1991 and 1990, when compared to the respective preceding year, primarily as a result of higher property taxes. Increases in the mill levies as well as higher assessed property values contributed to the higher property taxes in both years.

The reduction in 1991 income tax expense, when compared to 1990, was for the most part attributable to decreased income before income taxes and the recognition of higher tax deductions in the current year for which no deferred taxes were provided. Higher income before income taxes was the primary reason for the increase in 1990 income tax expense when compared to 1989. The 1989 income tax expense was, however, affected by two significant items. Income tax expense was lower in 1989 due to a revision in the amount of deferred taxes to be recognized as a result of taxable contributions in aid of construction under the Tax Reform Act of 1986 (see Note 9, Income Tax Expense in the Notes to Consolidated Financial Statements). This reduction was offset by lower tax benefits due to the recognition of deferred tax benefits associated with the 1986 Fort St. Vrain extraordinary loss. The deferred tax benefits were recognized at higher rates than those in effect for such actual deductions included in the 1989 tax return.

The increase in 1991 miscellaneous income and deductions-net over 1990 resulted primarily from the recognition in 1991 of a $3 million incentive award for the Company's efforts in securing a $67 million refund for its customers from one of the Company's natural gas suppliers.

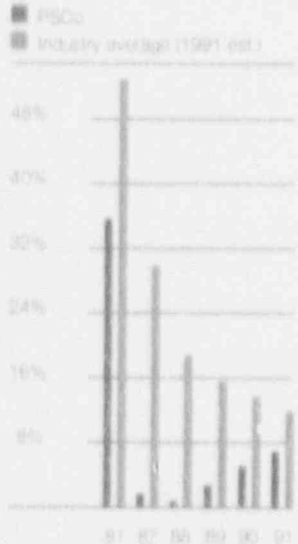
Interest expense increased in 1991, when compared to the previous year, as a result of an increase of $91.5 million in long-term debt issued throughout the year. The decline in interest expense in 1990, when compared to 1989, was primarily due to a decrease in interest expense on long-term debt. The decline was the result of the retirement of $35.5 million in first mortgage bonds and $25.0 million in medium-term notes in the first quarter of 1990. The positive effect of these retirements was mitigated by increased interest expense resulting from the issuance of $75.0 million in first mortgage bonds in July, 1990.

COMPOSITE FUEL COST PER MILLION BTU



Average cost of fuels for electric generation has been stable and below industry average.

AFDC—% OF EARNINGS



Allowance for Funds Used During Construction measures the portion of earnings derived from non-cash credits to income based on the cost of funds used to finance construction. Lower ratios mean higher quality of earnings.

Recently Issued Accounting Standards Not Yet Adopted

In December 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106 - "Employers' Accounting for Postretirement Benefits Other Than Pensions", which establishes the accounting and reporting standards for postretirement benefits other than pensions. While the Company believes adoption of the new standard will not have a material adverse financial impact, see Note 8, Employee Benefits in the Notes to Consolidated Financial Statements for a detailed discussion.

In December 1991, the FASB issued Statement of Financial Accounting Standards No. 107 - "Disclosures About Fair Value of Financial Instruments", which establishes disclosure requirements related to the fair value of financial instruments. This statement is effective for years ending after December 15, 1992, and the Company intends to adopt it in 1992. Since the future fair market value of financial instruments is not currently determinable, the Company believes that discussion, at this time, of any anticipated future effects from adoption of these disclosure requirements would not be meaningful.

In February 1992, the FASB issued Statement of Financial Accounting Standards No. 109 - "Accounting for Income Taxes", which supersedes Statement of Financial Accounting Standards No. 96 - "Accounting for Income Taxes." This statement is effective for fiscal years beginning after December 15, 1992. While the Company believes adoption of the new standard will not have a material adverse financial impact, see Note 9, Income Taxes in the Notes to Consolidated Financial Statements for a detailed discussion.

Commitments and Contingencies

The Company is involved with two sites designated under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) as hazardous waste sites, the Lowry Landfill site and the Barter Metals Company site. The Company is eligible to participate in a *de minimis* settlement for the Lowry Landfill site and the Company's portion of the cleanup costs is estimated to be between $1.3 million and $2.7 million. It is anticipated that the Company will settle its obligation in this matter during the first half of 1992. The Barter site cleanup costs are estimated to be up to approximately $5 million. Negotiations among the parties associated with the Barter site will continue into 1992 with cleanup possibly beginning in the spring or summer. The Company believes that it is probable that costs incurred related to the cleanup of the Lowry Landfill and Barter sites will be recovered through insurance. See Note 7, Commitments and Contingencies in the Notes to Consolidated Financial Statements for a detailed discussion.

Rate issues and commitments associated with the purchase of assets from Colorado-Ute Electric Association, Inc. as well as other commitments and contingencies are discussed in detail in Note 7, Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Impact of Inflation and Changing Prices

Capital intensive industries, such as the utility industry, are particularly affected by significant long-term inflation. Very simply, depreciation on utility property, plant and equipment, which is charged against earnings for assets acquired in the past, does not reflect the inflated cost of acquiring similar assets. Consequently, higher profits may be reported on a continuing basis with no accompanying gain in real purchasing power or economic value. However, the stabilization of inflation at relatively low levels has minimized this impact on the current operating results.

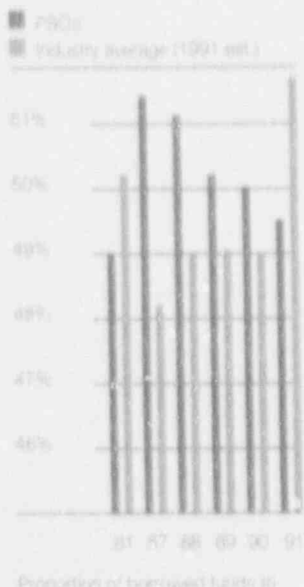
Liquidity and Capital Resources

Historical Cash Flows

Cash provided by operations remained relatively stable, when compared to 1990, increasing only $6.7 million. The

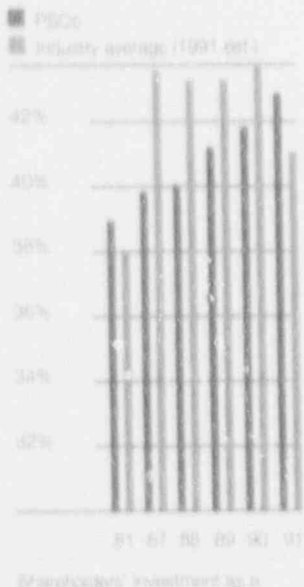
Company, however, has recognized a $124.4 million regulatory asset and a corresponding increase in the defueling and decommissioning liability as a result of the Fort St. Vrain Supplemental Settlement Agreement (see Note 2. Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements). These offsetting amounts are reflected in "deferred amounts" and "noncurrent defueling and decommissioning liability." Net cash provided by operations in 1990 increased $5.5 million, when compared to 1989, despite a decline in 1990 net income of $2.7 million. A net increase of $27.x million in Fort St. Vrain defueling and decommissioning expenditures charged to the liability was more than offset by a $28.8 million increase in 1990 refunds from gas suppliers.

DEBT RATIO



Proportion of borrowed funds to the total $2 billion invested in the Company

COMMON EQUITY RATIO



Shareholders' investment as a percent of the $2 billion invested in the Company

Cash used in investing activities was $29.6 million lower in 1991, when compared to 1990, primarily due to the funding of corporately held insurance policies using long-term investments rather than short-term investments. The increase in cash used in investing activities in 1990, when compared to 1989, was primarily due to an additional $86.8 million in 1990 construction expenditures as well as the funding of premiums on corporately held insurance policies using temporary cash investments rather than longer-term investments.

While net cash used in financing activities remained relatively stable in 1991, when compared to 1990, there was a significant increase in short-term and long-term financing activity. The 1991 activity in short-term financing resulted in net repayments of $13.2 million whereas the 1990 activity resulted in net borrowings of $60.6 million. The 1991 long-term debt activity resulted in net borrowings of $54.3 million compared to net repayments of $10.3 million in 1990.

The decline in cash used in financing activities in 1990, when compared to 1989, was primarily due to the net effect of a $19.3 million increase resulting from the issuance of common stock, the issuance of $75.0 million in first mortgage bonds and a $37.8 million net increase in short-term borrowings offset by the redemption of $35.5 million in first mortgage bonds and $25.0 million in medium-term notes in 1990.

Prospective Capital Requirements and Sources

At December 31, 1991, the Company and its subsidiaries estimated the cost of their construction program, including Allowance for Funds Used During Construction (AFDC) and other capital requirements, in 1992, 1993 and 1994 to be as follows:

(Thousands of Dollars)	1992	1993	1994
Company:			
Electric:			
Production*	$ 63,363	$ 49,525	$ 39,957
Transmission	29,857	35,034	26,831
Distribution	72,977	62,159	63,339
Gas	27,893	25,509	26,816
General**	52,281	49,743	44,392
Subtotal	246,371	221,969	200,335
Subsidiaries	33,331	66,277	85,369
Total construction	279,702	288,246	285,704
Less: AFDC	10,816	10,322	10,836
Add: Sinking funds and debt maturities	96,049	5,306	61,107
Add: Colorado-Ute Acquisition	294,394		-
Add: Colorado-Ute Capital Expenditures	4,549	15,727	2,171
Add: Fort St. Vrain Decommissioning/ Defueling***	18,136	60,566	55,705
Total capital requirements	$682,014	$359,527	$393,851

* Capital requirements for Electric Production include $3.5 million for Fort St. Vrain repowering. They are also net of Department of Energy funding of clean coal technology projects of $13.2 million for the 1992-1994 period.

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

*** Capital requirements for decommissioning and defueling assume the early dismantlement/decommissioning approach and are net of escrow funds available.

The construction program of the Company and its subsidiaries is 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 as discussed in Note 2. Fort St. Vrain Nuclear Generating Station in the Notes to Consolidated Financial Statements.

At December 31, 1991, the Company and its subsidiaries estimated that their 1992-1994 capital requirements would be met principally with approximately $785.4 million from external sources and with funds from operations. The

Company and its subsidiaries may meet their external capital requirements through the issuance of first mortgage bonds, preferred and/or common stock, by increasing the level of intermediate-term borrowing under PS Colorado Credit Corporation's (PSCCC) medium-term note program or through short-term borrowing under committed or 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.

In 1991, the Company amended the Automatic Dividend Reinvestment and Common Stock Purchase Plan whereby its shareholders may purchase additional shares of common stock of the Company through the reinvestment of cash dividends at a 3% discount for new issue shares and no price discount on open market shares. Additional shares of common stock may also be purchased with optional cash payments with no price discount. The 1992-1994 proceeds from the dividend reinvestment plan, estimated at approximately $125 million, will also provide funds to meet the capital requirements of the Company.

At December 31, 1991, the Company and its subsidiaries had temporary cash investments of $22.8 million.

As of December 31, 1991, PSCCC had borrowed $158.7 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 intermediate-term debt securities. As of December 31, 1991, PSCCC had no intermediate-term debt 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 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, 1991, $91.5 million principal amount of medium-term notes had been issued.

The Company's Indenture 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. At December 31, 1991, the amount of net additions would permit (and the net earnings test would not prohibit) the issuance of approximately $297.4 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 8.55%. Coverage under the net earnings test, at December 31, 1991, was 5

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, 1991, gross income available under this requirement would permit the Company to issue approximately $1.5 billion of additional preferred stock at an assumed annual dividend rate of 7.62%. Coverage of gross income to interest charges, at December 31, 1991, was 3.52.

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, 1991, the Company had outstanding unsecured indebtedness, including subsidiary indebtedness with the credit support of the Company, in the amount of $96.0 million. The maximum amount permitted under this limitation was approximately $315.9 million at December 31, 1991.

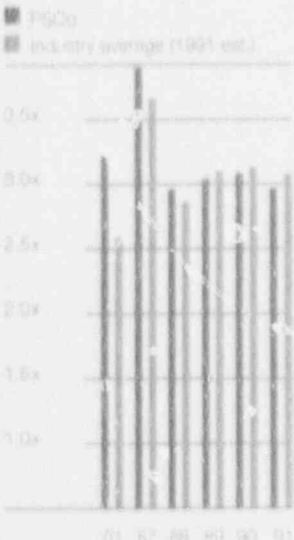
Arrangements for bank lines of credit totaled $300 million in committed lines and $60 million in uncommitted lines at December 31, 1991, at which time $171.5 million was available to the Company and PSCCC. The Company could generally borrow under uncommitted preapproved lines of credit upon request; however, the banks have no firm commitment to make such loans.

At December 31, 1991, Western Gas Supply Company (WestGas) Cheyenne Light, Fuel and Power Company (Cheyenne) and Natural Fuels Corporation had individual arrangements for committed bank lines of credit of $25 million, $2 million and $4 million, respectively. The unused amounts of these committed lines of credit at December 31, 1991 were $12.9 million, $2 million, and $3.9 million, respectively.

On January 15, 1992, the Company and PSCCC extended the credit facility jointly entered into on February 8, 1991. The credit facility with several banks provides $300 million in bank lines of credit. The credit facility, which is used primarily to support the issuance of commercial paper by the

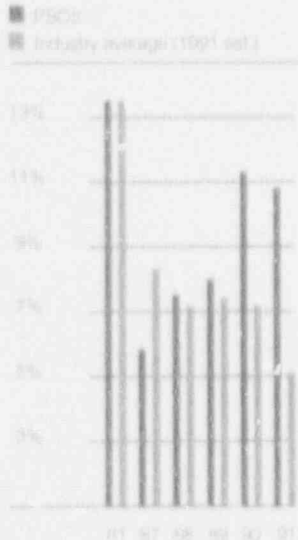
Company and PSCCC, alternatively provides for direct borrowing thereunder. With this extension, Bannock Center Corporation, Cheyenne, 1480 Welton, Inc., Fuel Resources Development Co. and WestGas were provided access to the credit facility under a $100 million aggregate sub-limit with direct borrowings guaranteed by the Company. Generally, the banks as participants 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 facility expires December 31, 1992 (see Note 6. Bank Lines of Credit and Compensating Bank Balances in the Notes to Consolidated Financial Statements).

PRETAX COVERAGE OF INTEREST EXPENSE



Times interest earned, a measure of protection for bondholders.

CONSTRUCTION EXPENDITURES AS A % OF CAPITALIZATION



New investment as a percent of existing investment.

Report of Management

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

The Company maintains and enforces a system of internal controls, which is designed to provide reasonable assurance, on a cost effective basis, as to the integrity, objectivity and reliability of the financial records. This system includes a program of internal audits to assure management that proper procedures and methods of operation are used to implement the plans, policies and directives of management. Management has considered the internal auditor's and the independent public accountants' recommendations during the year concerning the Company's system of internal controls and has taken actions that we believe are cost effective in the circumstances. Management believes that, as of December 31, 1991, the Company's system of internal controls is adequate to accomplish the objectives discussed above. Furthermore, the accounting procedures and internal control system of the Company are reviewed by the Audit Committee of the Board of Directors.

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 financial records and related data, as well as representations we believe to be valid and appropriate.

W. Wayne Brown
Principal Accounting Officer

D. D. Hock
Chief Executive Officer

February 14, 1992

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 1991, 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 19, 1992

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, 1991 and 1990, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1991. 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, 1991 and 1990, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1991, 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 $61.5 million at December 31, 1991) as well as the tax effects of previously recognized tax deductions associated with such investment for which no deferred taxes were required to be provided (approximately $7.5 million at December 31, 1991) 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 $192.4 million at December 31, 1991) 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.

Arthur Andersen & Co

Arthur Andersen & Co.
Denver, Colorado

February 19, 1992

CONSOLIDATED STATEMENTS OF INCOME

Public Service Company of Colorado and Subsidiaries — *Years ended December 31, 1991, 1990 & 1989*

(Thousands of Dollars Except Per Share Data)	1991	1990	1989
Operating Revenues:			
Electric	**$1,180,501**	$1,145,915	$1,139,471
Gas	**587,609**	561,712	577,282
Other	**26,794**	26,312	23,913
	1,794,904	1,733,939	1,740,666
Operating Expenses:			
Fuel used in generation	**177,365**	166,784	165,801
Purchased power	**323,793**	301,910	295,025
Gas purchased for resale	**365,991**	358,263	380,078
Other operating expenses	**361,610**	332,516	329,991
Maintenance	**67,216**	85,522	86,755
Depreciation	**111,728**	106,527	102,831
Taxes (other than income taxes) (Note 10)	**74,335**	70,033	67,430
Income taxes (Note 9)	**69,288**	73,978	66,557
	1,551,326	1,495,533	1,494,468
Operating Income	**243,578**	238,406	246,198
Other Income and Deductions:			
Allowance for equity funds used during construction (Note 1)	**4,763**	3,444	1,581
Miscellaneous income and deductions-net	**2,889**	1,590	1,485
	251,230	243,440	249,264
Interest Charges:			
Interest on long-term debt	**81,666**	75,075	77,627
Amortization of debt discount and expense less premium	**1,827**	1,543	1,385
Other interest	**22,718**	23,949	23,456
Allowance for borrowed funds used during construction (Note 1)	**(4,674)**	(3,271)	(2,044)
	101,537	97,296	100,424
Net Income	**149,693**	146,144	148,840
Dividend Requirements on Preferred Stock	**12,234**	12,439	12,645
Earnings Available for Common Stock	**$ 137,459**	$ 133,705	$ 136,195
Shares of Common Stock Outstanding (thousands):			
Year-end	**56,294**	54,320	52,807
Weighted average	**55,471**	53,626	52,559
Earnings Per Weighted Average Share of Common Stock Outstanding	**$2.48**	$2.49	$2.59
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, 1991 & 1990

Assets	**1991**	1990
	(Thousands of Dollars)	
Property, Plant and Equipment, at Cost:		
Electric	**$2,784,646**	$2,650,088
Gas	**871,843**	808,818
Steam and other	**95,324**	97,985
Common to all departments	**271,991**	258,745
Construction in progress	**171,698**	145,333
	4,195,502	3,960,969
Less: Accumulated depreciation	**1,511,162**	1,412,443
	2,684,340	2,[illegible]48,526
Fort St. Vrain related property (Note 2)	**78,242**	[illegible],802
Less: Accumulated depreciation	**16,782**	17,067
	61,460	60,735
Total Property, Plant and Equipment	**2,745,800**	2,609,261
Investments, at Cost	**111,572**	116,029
Current Assets:		
Cash	**13,509**	8,928
Temporary cash investments	**22,765**	18,256
Accounts receivable, less reserve for uncollectible accounts ($4,741 at December 31, 1991; $4,370 at December 31, 1990)	**144,869**	127,845
Gas refund receivable	**-**	14,979
Accrued unbilled revenues (Note 1)	**62,539**	66,506
Recoverable purchased gas and electric energy costs-net (Note 1)	**44,702**	65,870
Materials and supplies, at average cost	**78,367**	71,919
Fuel inventory, at average cost	**34,447**	33,427
Gas in underground storage, at cost (LIFO)	**14,803**	13,701
Prepaid expenses	**14,409**	11,453
Other	**1,199**	831
Total Current Assets	**431,609**	433,715
Deferred Charges:		
Unamortized debt expense	**19,491**	20,012
Recoverable nuclear plant and decommissioning costs (Note 2)	**124,444**	5,025
Gas refund receivable	**-**	29,957
Other	**39,873**	29,073
	183,808	84,067
Total Assets	**$3,472,789**	$3,243,072

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

Capital and Liabilities	1991	1990
	(Thousands of Dollars)	
Common Equity:		
Common stock (Note 3)	$ 795,718	$ 751,149
Retained earnings	238,715	212,514
	1,034,433	963,663
Preferred Stock (Note 3):		
Not subject to mandatory redemption	140,008	140,008
Subject to mandatory redemption at par	43,792	46,368
Long-Term Debt (Note 4)	900,491	896,029
	2,118,724	2,046,068
Noncurrent Liabilities:		
Defueling and decommissioning liability (Note 2)	145,331	13,197
Gas refund liability	749	29,957
	146,080	43,154
Current Liabilities:		
Notes payable and commercial paper (Note 5)	200,640	213,833
Long-term debt due within one year	93,474	42,235
Preferred stock subject to mandatory redemption within one year (Note 3)	2,576	2,576
Accounts payable	171,805	177,753
Dividends payable	31,171	30,236
Customers' deposits	15,842	15,071
Accrued taxes	76,343	64,876
Accrued interest	24,401	20,701
Gas refund liability	49,975	41,162
Current portion of defueling and decommissioning liability (Note 2)	47,034	82,169
Other	51,829	48,918
Total Current Liabilities	765,090	739,530
Deferred Credits:		
Customers' advances for construction	46,927	40,768
Unamortized investment tax credits	134,386	139,616
Accumulated deferred income taxes (Note 9)	251,481	225,359
Other	10,101	8,577
	442,895	414,320
Commitments and Contingencies (Notes 2 and 7)		
Total Capital and Liabilities	$3,472,789	$3,243,072

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Public Service Company of Colorado and Subsidiaries *Years ended December 31, 1991, 1990 & 1989*

	1991	(Thousands of Dollars) 1990	1989
Retained Earnings at Beginning of Year	**$212,514**	$186,284	$155,232
Net Income	**149,693**	146,144	148,840
	362,207	332,428	304,072
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	**1,665**	1,755	1,845
8.40% series	**2,139**	2,254	2,370
$25 par value:			
8.40% series	**2,940**	2,940	2,940
	12,200	12,405	12,611
On common stock:			
$2.00 per share in 1991, 1990 and 1989	**111,292**	107,509	105,177
	123,492	119,914	117,788
Retained Earnings at End of Year	**$238,715**	$212,514	$186,284

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, 1991, 1990 & 1989*

	1991	(Thousands of Dollars) 1990	1989
Operating Activities:			
Net income	**$ 149,693**	$ 146,144	$ 148,840
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**118,943**	113,426	115,763
Amortization of investment tax credits	**(5,230)**	(4,982)	(5,267)
Deferred income taxes	**26,122**	34,287	37,020
Allowance for equity funds used during construction	**(4,763)**	(3,444)	(1,581)
Change in accounts receivable	**(17,024)**	8,378	11,414
Change in inventories	**(8,570)**	8,350	(15,448)
Change in other current assets	**21,811**	(17,964)	(7,842)
Change in accounts payable	**(5,948)**	13,319	21,609
Change in other current liabilities	**(11,022)**	40,234	47,521
Change in gas refunds-net	**24,541**	22,294	(6,523)
Change in deferred amounts	**(122,554)**	1,998	12,319
Change in noncurrent defueling and decommissioning liability	**132,134**	(71,903)	(63,266)
Other	**2,134**	3,385	(6,525)
Net Cash Provided by Operating Activities	**300,267**	293,522	288,034
Investing Activities:			
Construction expenditures	**(260,704)**	(261,221)	(174,418)
Allowance for equity funds used during construction	**4,763**	3,444	1,581
Proceeds from disposition of equipment	**5,893**	5,321	3,949
Purchase of other investments	**(11,396)**	(49,367)	(129,861)
Sale of other investments	**15,002**	25,798	137,827
Net Cash Used in Investing Activities	**(246,442)**	(276,025)	(160,922)
Financing Activities:			
Proceeds from sale of common stock (Note 1)	**39,305**	27,881	8,570
Proceeds from sale of long-term notes and bonds	**97,204**	83,684	19,843
Redemption of long-term notes and bonds	**(42,918)**	(94,008)	(48,228)
Proceeds from short-term borrowings	**690,645**	142,793	222,790
Repayment of short-term borrowings	**(703,838)**	(82,168)	(199,950)
Redemption of preferred stock	**(2,576)**	(2,576)	(2,576)
Dividends on common stock	**(110,306)**	(106,753)	(105,002)
Dividends on preferred stock	**(12,251)**	(12,456)	(12,662)
Net Cash Used in Financing Activities	**(44,735)**	(43,603)	(117,215)
Net Increase (Decrease) in Cash and Temporary Cash Investments	**9,090**	(26,106)	9,897
Cash and Temporary Cash Investments at Beginning of Year	**27,184**	53,290	43,393
Cash and Temporary Cash Investments at End of Year	**$ 36,274**	$ 27,184	$ 53,290

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

1. Summary of Significant Accounting Policies

Consolidation

Public Service Company of Colorado (the Company) follows the practice of consolidating the accounts of its subsidiaries. All intercompany items and transactions have been eliminated.

Revenue recognition

The Company and Cheyenne Light, Fuel and Power Company (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 fiscal period.

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 capitalized interest) paid:

		(Thousands of Dollars)	
	1991	1990	1989
Income taxes	$44,418	$43,119	$37,672
Interest	$96,010	$95,236	$99,653

Non-cash transactions:
During 1991 and 1990, 242,674 and 197,862 shares of common stock, respectively, valued at the market price on date of issuance (approximately $5.3 million in 1991 and $5.0 million in 1990), 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 as a source of cash in the consolidated statements of cash flows. No material non-cash investing or financing transactions were recorded during 1989.

Depreciation

The Company and its subsidiaries use straight-line depreciation for accounting purposes. Composite rates are used for the various classes of depreciable assets. Depreciation rates include provisions for disposal and removal costs of property, plant and equipment. Total depreciation expense in 1991 approximates an annual rate of 3.0% on the average cost of depreciable properties.

Replacements and betterments representing units of property are capitalized. Items that represent less than units of property are charged to operations as maintenance. The cost of units of property retired, together with cost of removal, less salvage, is charged in full against 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 Federal Energy Regulatory Commission (FERC) and The Public Utilities Commission of the State of Colorado (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 range of AFDC rates were used for the years 1991, 1990 and 1989.

	1991	1990	1989
AFDC rates	8.76%-10.21%	8.76%-10.21%	9.78%-10.21%

Income taxes

The Company and its significant 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.

The Company and its regulated subsidiaries, Western Gas Supply Company (WestGas) and Cheyenne, provide 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 currently provides for deferred taxes on book-tax timing differences arising from items associated with Fort St. Vrain (see Note 2), from certain customer refunds and for all book-tax timing differences included in FERC jurisdictional rates. All of the Company's non-regulated subsidiaries, 1480 Welton, Inc. (1480), Fuelco, Bannock Center Corporation (BCC), PSR Investments, Inc., and PS Colorado Credit Corporation (PSCCC), provide for deferred taxes arising from all book-tax timing differences.

As a result of the Tax Reform Act of 1986, the Company determines its income tax to be the greater of regular income tax or alternative minimum tax (AMT). Any excess of AMT over regular income tax becomes a credit which may be applied against future regular tax liabilities.

Investment tax credits are no longer available to the Company and its subsidiaries as a result of the Tax Reform Act of 1986. Previously recorded investment tax credits have been deferred and are being amortized to income over the productive lives of the related property.

Amortization of debt premium, discount and expense

Debt premium, discount and expense is being amortized to income over the respective original lives of the applicable issues or as directed by the CPUC.

Recoverable purchased gas and electric energy costs–net

The Company, Cheyenne and WestGas 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. 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.

Reclassification

Certain items in the 1990 and 1989 Consolidated Financial Statements have been reclassified to conform to the 1991 manner of presentation.

2. Fort St. Vrain Nuclear Generating Station

Investment in Fort St. Vrain

On August 29, 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 commenced the defueling process as discussed below in the section entitled "Defueling".

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 $61.5 million at December 31, 1991), as well as the tax effects of previously recognized tax deductions associated with such investment for which no deferred taxes were required to be provided (approximately $7.5 million at December 31, 1991), is primarily dependent on the Company's ability to repower the facility as a natural gas fired plant, which it intends to complete by 1998 when the Company currently estimates it will need the capacity available from the converted plant. The Company will be required to obtain a certificate of public convenience and necessity from the CPUC. If it becomes probable that all or a portion of such investment and/or the related 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.

During 1991, as a result of spent fuel shipment delays and a higher probability of utilization of the on-site independent spent fuel storage installation (ISFSI) (discussed below under "Defueling"), the Company recognized an additional $13.1 million in defueling and decommissioning expenses. Other operating expenses in 1991 also include present value adjustments of approximately $7.9 million to the defueling and decommissioning liability. Similar adjustments in 1990 and 1989 of approximately $10.9 million and $14.2 million, respectively, were included in other operating expenses. In addition, 1990 maintenance expenses include approximately $8.2 million associated with impaired nuclear assets, primarily related to the write-down of nuclear materials and supplies inventory. During 1989, the plant's final year of operation, Fort St. Vrain did not produce revenues adequate to offset expenses. Accordingly, an additional shortfall of approximately $15.9 million in unrecoverable operating and capital expenditures was recognized in 1989.

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 a three year period.)

Pursuant to the Agreement, the Company will recover from customers approximately $124.4 million, plus a 9% carrying cost, which represents the inflation adjusted estimated remaining cost of the early dismantlement/decommissioning activities not previously recognized as expense, over a twelve year period, beginning July 1, 1993. The annual amount charged to customers each year will be approximately $13.9 million. As a result, a $124.4 million regulatory asset and a corresponding increase in the defueling and decommissioning liability has been included in the consolidated balance sheet.

In consideration for the authorization to charge this annual amount to customers, the Agreement stipulates that the Company will adhere to certain ratemaking principles during the twelve year period as follows:

• No adjustment will be made for regulatory purposes to the Company's capital structure that would result in the allocation of the previously recognized Fort St. Vrain write-downs to all components of the capital structure rather than to common equity alone.

• With respect to construction work in progress (CWIP) the present regulatory treatment (exclusion of CWIP from rate base) will continue, provided that the Company may request an exception in the event certain larger power plant projects are pursued, excluding the repowering of Fort St. Vrain.

• The Company will implement accrual accounting for regulatory purposes in accordance with the provisions of Statement of Financial Accounting Standards No. 106 - "Employers' Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106), modified in certain respects (see Note 8).

• For regulatory purposes, administrative and general costs will be allocated to Fort St. Vrain so as to reflect the portion of such costs attributable to Fort St. Vrain.

In addition, the Company has committed to make contributions to the Colorado Energy Assistance Foundation for a thirteen year period. In the event the Company commences litigation to recover damages associated with spent fuel shipping delays (discussed below under "Defueling"), the Company's electric customers will be entitled to a refund or credit equal to one-half of any net cash payment (after fees, including legal fees) received by the Company.

The Company has submitted a proposed early dismantlement/decommissioning plan to the Nuclear Regulatory Commission (NRC) and 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. The contract stipulates a fixed price, based on the defined work scope; however, such price could be revised due to changes in the work scope or changes in certain regulations. Generally, contract termination by the Company would result in the Company being responsible for all contractor incurred costs to the date of notice of termination plus reasonable costs associated with settlement expenses related to the cessation of work.

Beginning in the fourth quarter of 1991, adoption of the early dismantlement/decommissioning approach eliminated the need for any future present value adjustment charges to earnings associated with the defueling and decommissioning liability. Prior to the issuance of the December 27, 1991 CPUC decision, the Company was also considering the SAFSTOR option for decommissioning, which assumed that following defueling, the nuclear portion of the plant would be prepared for a prolonged decay period (approximately 51 years), after which decommissioning would be completed with the four-year dismantlement of the reactor. Due to the extended time frame for completion of this decommissioning approach, the SAFSTOR cost estimate had been determined on a present value basis which required quarterly expense adjustments to recognize the passage of time.

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, 1991:

	(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
CPUC approved additional cost recovery-12/31/91	124,444
Present value adjustments accrued through 9/30/91	36,428
	333,139
Defueling expenditures through 12/31/91	(128,040)
Decommissioning expenditures through 12/31/91	(12,734)
Defueling and decommissioning liability-12/31/91	$192,365*
*Defueling	$ 36,198
Decommissioning	156,167
	$192,365

Because of the uncertainty as to completion of decommissioning at currently estimated costs and the fact that the decommissioning plan is subject to NRC approval, 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 because of any changes which may be required in the decommissioning plan by the NRC or others or because of the resolution of other uncertainties such as the disposal of spent fuel as discussed below.

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 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 beginning 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 is currently pursuing 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, 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 (discussed below).

While the plant was operating, 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, the Governor of Idaho contested the shipment of Fort St. Vrain spent nuclear fuel to the State of Idaho. As a result, several lawsuits were commenced during 1991 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 has been successful in shipping some fuel elements to the INEL since the initiation of these lawsuits, the Company is not currently making any shipments due to the DOE being enjoined from receiving Fort St. Vrain spent fuel by a preliminary injunction issued by the U. S. District Court for the District of Idaho.

While the Company intends to pursue all available legal actions to enable it to ship the spent fuel to Idaho, the eventual outcome of the litigation, and its timing, are uncertain. 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. The Company currently anticipates completion of defueling to the ISFSI by August 1992. Recognition of the additional $13.1 million in defueling and decommissioning expenses during 1991 allows for the utilization of this facility for an interim period of time without the recognition of additional expense. The Company believes the defueling and decommissioning liability currently recorded on the books is adequate assuming that (i) the fuel is stored in the ISFSI until 1993 and (ii) at that time, the spent fuel is shipped to the INEL with completion of shipping by the end of 1995.

If 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 when such fuel would be shipped to an assumed available Federal repository, the Company would be required to recognize an additional defueling expense for maintaining the ISFSI during this extended period. At December 31, 1991, such expense was estimated to be approximately $13 million, determined on a present value basis. These expenditures have been escalated at an average annual rate of 5.3% and discounted to present value at a rate of 9%. In this situation, costs associated with the shipment of the fuel from the ISFSI to the Federal repository in 2020 are assumed to be the responsibility of the DOE and, therefore, are 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. The plan must provide for the technical and operational aspects of decommissioning and specify that provision will be made for the costs of decommissioning (not including defueling) through NRC prescribed methods of funding which are: (1) lump sum prepayment, (2) an external sinking fund with annual payments, or (3) a guarantee method (such as insurance, surety bond, letter of credit or line of credit). Within two years after cessation of operations, a licensee must submit its funding plan to the NRC to assure the availability of funds for completion of decommissioning. On January 27, 1992, the NRC approved the Company's funding decommissioning plan. The Company has also obtained a commitment from a financial institution, subject to execution of final documentation, to issue an unsecured irrevocable letter of credit that will meet the NRC's stipulated funding guidelines including those proposed on August 21, 1991 by the NRC that address decommissioning funding requirements for nuclear power reactors that have been prematurely shut down. The issuance of the irrevocable letter of credit is subject to, among other things, the approval of the Company's decommissioning plan by the NRC.

The Company has previously set aside funds for decommissioning the reactor in trust accounts that total approximately $28.8 million at December 31, 1991. Approximately $22.5 million of this amount represents funds recovered from customers and the earnings from the trust accounts. The remaining $6.3 million, which was contributed to the trust accounts in 1989 and 1990, represents funds not specifically recovered from customers. In addition, during December 1991, the Company established a separate decommissioning trust for the ISFSI and contributed

$1.4 million to the trust. It is anticipated that this contribution, together with the expected earnings on the funds, will be sufficient to decommission the ISFSI in 1995.

Defueling and other fuel related costs, of which the majority are scheduled to occur through 1992 and which the Company is not required to prefund, are being 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. Effective July 1, 1989, the Company maintains $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 responsible 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 $66 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.

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 will cover stabilization and decontamination expenses resulting from a worst case defueling accident. The Company currently maintains $281 million in property insurance coverage. The additional insurance coverage above the $169 million is necessary to provide for the estimated depreciated replacement value of the plant assets that will be used in the repowering of Fort St. Vrain.

3. Capital Stock

	1991		1990	
	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
4¼% series (includes $7,500 premium)	175,000	17,508	175,000	17,508
4½% 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	228,000	$ 22,800
8.40% series	247,680	24,768	261,440	26,144
	463,680	46,368	489,440	48,944
Less: Preferred stock subject to mandatory redemption within one year	(25,760)	(2,576)	(25,760)	(2,576)
Total	437,920	$ 43,792	463,680	$ 46,368
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
Common stock, $5 par value:				
Authorized	140,000,000		140,000,000	
Issued and outstanding	56,293,525	$281,468	54,320,248	$271,601
Premium on common stock		514,250		479,548
		$795,718		$751,149

Changes in common stock and premium on common stock for the three years ended December 31, 1991 are as follows:

	Average Price Per Share	Common Stock	(Thousands of Dollars) Premium on Common Stock
Balance, January 1, 1989		$262,289	$447,437
348,733 shares issued under the Dividend Reinvestment Plan	$24.53	1,744	6,811
615 share adjustment	$23.75	3	12
Balance, December 31, 1989		264,036	454,260
197,862 shares issued under the Employees' Savings Plan	$25.13	989	3,983
1,315,163 shares issued under the Dividend Reinvestment Plan	$21.20	6,576	21,305
Balance, December 31, 1990		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

On February 26, 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.

During each of the years 1991, 1990 and 1989, the Company repurchased 12,000 shares of the 7.50% cumulative preferred series and 13,760 shares of the 8.40% cumulative preferred series subject to mandatory redemption at $100 per share plus accrued dividends to the date set for purchase. No other changes in preferred stock occurred in the three years ended December 31, 1991.

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

$100 par value:

Not subject to mandatory redemption:
4.20% series: $101; 4 1/4% series: $101; 4 3/4% series: $101; 4.64% series: $101; 4.90% series: $101; 4.90% 2nd series: $101; 7.15% series: $101.

Subject to mandatory redemption:
7.50% series: $103 on or prior to August 31, 1992, reducing each year thereafter by $0.25 per share until August 31, 2003, after which the redemption price is $100; 8.40% series: $103.25 on or prior to July 31, 1992, and reducing each year thereafter by $0.25 per share until July 31, 2004, after which the redemption price is $100.

In 1992 and in each year thereafter, the Company must offer to repurchase 12,000 shares of the 7.50% series at $100 per share, plus accrued dividends to the date set for repurchase, and 13,760 shares of the 8.40% series 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, 1991 consolidated balance sheet.

$25 par value:

Not subject to mandatory redemption:
8.40% series: $25.25

4. Long-Term Debt

	1991	1990
	(Thousands of Dollars)	
Public Service Company of Colorado:		
First mortgage bonds:		
4⅝% series, paid October 1, 1991	$ –	$ 30,000
4⅜% series, due March 1, 1992	8,800	8,800
8.95% series, due May 1, 1992	75,000	75,000
4½% series, due June 1, 1994	35,000	35,000
5⅜% series, due May 1, 1996	35,000	35,000
5½% series, due July 1, 1997	35,000	35,000
6⅜% series, due July 1, 1998	25,000	25,000
8⅛% series, due September 1, 2000	35,000	35,000
7¼% series, due February 1, 2001	40,000	40,000
7⅞% series, due August 1, 2002	50,000	50,000
7¾% series, due June 1, 2003	50,000	50,000
9⅜% series, due October 1, 2005	49,500	49,500
8⅞% series, due November 1, 2007	50,000	50,000
9¼% series, due October 1, 2008	50,000	50,000
9⅞% series, due July 1, 2020	75,000	75,000
Pollution Control Series A,		
5⅞%, due March 1, 2004	24,000	24,000
Pollution Control Series B:		
7⅜%, due December 1, 1995	2,500	2,500
8%, due December 1, 2004	35,000	35,000
Pollution Control Series C:		
7¼%, due October 1, 2004	15,000	15,000
7⅜%, due October 1, 2005	1,960	1,960
7½%, due October 1, 2006	2,105	2,105
7⅝%, due October 1, 2007	2,260	2,260
7¾%, due October 1, 2008	2,425	2,425
7⅞%, due October 1, 2009	26,250	26,250
Pollution Control Series E,		
9⅜%, due May 1, 2013	42,000	42,000
Pollution Control Series F,		
7⅛%, due November 1, 2009	27,250	27,250
Secured Medium-Term Notes, Series A:		
8.38%, due January 12, 1994	10,000	–
8.375%, due January 17, 1994	10,000	–
8.55%, due January 11, 1995	20,000	–
8.82%, due January 15, 1996	15,000	–
8.90%, due August 1, 1997	5,000	–
8.90%, due August 15, 1997	5,000	–
9%, due April 1, 1998	5,000	–
9.08%, due March 15, 1999	10,000	–
8.90%, due August 10, 1999	5,000	–
9.25%, due March 27, 2001	6,500	–
Unamortized premium	545	615
Unamortized discount	(1,039)	(1,090)
Capital lease obligations, 8.40%-14.65%, due in installments through April 1, 1995	2,230	2,651
	$887,286	$ 826,226

	1991	1990
	(Thousands of Dollars)	
Cheyenne Light, Fuel and Power Company:		
First mortgage bonds:		
7⅜% series, due April 1, 2003	$ 4,000	$ 4,000
Industrial Development Revenue Bonds, 7.25%, due September 1, 2021	7,000	–
10.70 % unsecured notes, due September 1, 1995	8,000	8,000
Western Gas Supply Company:		
Unsecured promissory notes:		
7½%, due December 1, 1997	20,000	20,000
10.35%, due in installments through December 1, 1999	4,000	5,334
11.60%, due May 1, 2015	5,000	5,000
12.875%, due May 1, 2025	10,000	10,000
Unamortized discount	(292)	(305)
1480 Welton, Inc.:		
12.50% secured promissory note, due in installments through March 1, 1998	8,906	9,792
13.25% secured promissory note, due in installments through October 1, 2016	32,708	32,868
Fuel Resources Development Co.:		
Unsecured note, due June 30, 1992, interest rate fluctuates with the New York Federal Funds rate (4.49% at December 31, 1991 and 5.93% at December 31, 1990)	7,000	7,000
Bannock Center Corporation:		
8% mortgage note, due in installments through January 1, 1992	200	250
PS Colorado Credit Corporation:		
8.30% to 8.75% unsecured notes, maturing January 16, 1991 to February 5, 1991	–	10,000
Natural Fuels Corporation:		
12.25% secured note, due in installments through May 23, 1994	9	–
Capital lease obligations, 8¾% due in installments through August 31, 1996	148	99
	993,965	938,264
Less: Maturities due within one year	93,474	42,235
	$900,491	$ 896,029

In October of 1990, the Company filed a registration statement with the Securities and Exchange Commission relating to a $500,000,000 principal amount of First Mortgage Bonds of which $200,000,000 was subsequently designated for offering pursuant to a secured medium-term note program. As of December 31, 1991, the Company has issued $91,500,000 under the secured medium-term note program. The Company will continue from time to time to offer such secured medium-term notes and bonds based on market conditions and other factors.

At December 31, 1991, 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 $100,000,000 outstanding at any one time. There were no amounts outstanding at December 31, 1991, and $10,000,000 outstanding at December 31, 1990.

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 or the mortgage bonds and notes of subsidiaries.

The aggregate annual maturities and sinking fund requirements during the five years subsequent to December 31, 1991 are:

Year	Maturities	Sinking Fund Requirements	Total
1992	$93,474,000	$4,605,000	$98,079,000
1993	2,730,000	4,605,000	7,335,000
1994	57,301,000	4,755,000	62,056,000
1995	33,115,000	4,755,000	37,870,000
1996	51,233,000	5,505,000	56,738,000

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.

5. Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended December 31, 1991 and 1990 is as follows:

	1991	1990
	(Thousands of Dollars)	
Notes payable to banks (weighted average interest rates of 5.58% at December 31, 1991 and 8.54% at December 31, 1990)	**$ 12,100**	$ 68,733
Commercial paper (weighted average interest rates of 5.55% at December 31, 1991 and 9.06% at December 31, 1990)	**188,540**	145,100
	$ 200,640	$ 213,833
Maximum amount outstanding at any month-end during the period	**$ 200,640**	$ 254,230
Weighted average amount (based on the daily outstanding balance) outstanding for the period (weighted average interest rates of 6.47% for the year ended December 31, 1991 and 8.44% for the year ended December 31, 1990)	**$ 179,494**	$ 163,736

6. 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 February 8, 1991, the Company and PSCCC jointly entered into a credit facility with several banks providing $300,000,000 in bank lines of credit. The facility, which was to mature February 6, 1992, replaced the $300,000,000 individually arranged bank lines of credit in effect at the time this facility was entered into. There were $300,000,000 in available commitments on December 31, 1991, of which $111,500,000 remains unused. On January 15, 1992, the Company and PSCCC extended this credit facility to mature December 31, 1992. The facility, which is used primarily to support the commercial paper issuance of the Company and PSCCC, alternatively provides for direct borrowing thereunder. With this extension, BCC, Cheyenne, 1480 Fuelco and WestGas were provided access to the facility under a $100,000,000 aggregate sub-limit with direct borrowings thereunder guaranteed by the Company. 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.

At December 31, 1991, WestGas, Cheyenne and Natural Fuels Corporation (Natural Fuels) had individual arrangements for committed bank lines of credit of $25,000,000, $2,000,000 and $4,000,000, respectively. The unused amounts of these committed lines of credit at December 31, 1991 were $12,900,000, $2,000,000 and $3,864,000, respectively.

Individual arrangements for committed bank lines of credit totaled $150,000,000 at December 31, 1990, of which $136,000,000 was available. Certain of the agreements for those credit lines required that investment grade status be maintained to ensure commitment. These bank lines of credit were primarily used to support the issuance of commercial paper by the Company and PSCCC, but also allowed for direct borrowing thereunder.

Individual arrangements for uncommitted bank lines of credit totaled $60,000,000 at December 31, 1991 and $150,000,000 at December 31, 1990. The unused uncommitted lines of credit at December 31, 1991 and 1990 were $60,000,000 and $95,000,000, respectively. 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.

7. Commitments and Contingencies

Colorado-Ute Electric Association, Inc. (Colorado-Ute)

On September 26, 1991, the Company, Tri-State Generation and Transmission Association, Inc. (Tri-State), PacifiCorp Electric Operations (PacifiCorp) and Intermountain Rural Electric Association filed a Joint Plan of Reorganization (Joint Plan), which was amended October 31, 1991, in the Chapter 11 reorganization of Colorado-Ute, currently pending in the U.S. Bankruptcy Court.

The Company, Tri-State and PacifiCorp agreed to divide the electric load, assets and liabilities of Colorado-Ute. Under the agreement, Tri-State will serve ten cooperatives that will become members of Tri-State, representing about half the load of Colorado-Ute. The remaining four cooperatives, which serve approximately 105,000 customers and represent the other half of the Colorado-Ute load, will become customers of the Company.

The generating assets of Colorado-Ute, primarily the Craig and Hayden coal-fired plants in northwestern Colorado, will be divided among the Company, Tri-State and PacifiCorp. The Company will acquire approximately 332 megawatts (Mw) as follows:

Hayden 1	139 Mw
Hayden 2	98 Mw
Craig 1	41.5 Mw
Craig 2	41.5 Mw
Various Hydro Plants	11.6 Mw

Tri-State will acquire 100 Mw and assume the Craig 3 lease of 408 Mw, and PacifiCorp will acquire 243 Mw. The Company will operate the Hayden Station. Tri-State will operate the Nucla fluidized bed coal facility and the Craig Station. PacifiCorp will acquire two-thirds of Colorado-Ute's interest in the Trapper Mine with Tri-State acquiring the remaining one-third interest.

In addition, the Company will enter into various purchase power agreements with Tri-State for the purchase of 200 Mw and PacifiCorp for the purchase of 176 Mw. The Tri-State purchase agreements will be in addition to the existing purchase agreements between the Company and Tri-State. Short-term firm purchases will be decreased as a result of these new purchase power agreements.

The Company will also acquire transmission lines to serve the new customers and will acquire joint ownership with Tri-State in various bulk power transmission lines throughout Colorado. These transmission lines will give the Company access to the Four Corners area in southwest Colorado as well as provide transmission paths for transmitting the acquired capacity discussed above into the Company system.

It is anticipated that creditors will be paid in full under the Joint Plan. The Company will pay approximately $300 million and PacifiCorp will pay approximately $150 million. The payments will be designated for satisfaction of secured debt and unsecured creditors. Tri-State will assume the Craig 3 lease and the balance of the Colorado-Ute secured debt of approximately $270 million. The Company expects to finance this asset acquisition with debt instruments.

The bankruptcy court confirmed the Joint Plan on February 19, 1992. Prior to confirmation, various federal and state regulatory agencies, various groups of creditors and other numerous parties to operating agreements with Colorado-Ute had approved the Joint Plan. The Company has filed an application for expedited approval by the FERC for the portions of the Joint Plan under FERC jurisdiction. The Company anticipates receiving FERC approval and expects to complete the acquisition of assets in the spring of 1992.

Rate issues

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 three 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. The Settlement Agreement addressing revenue requirements provided, among other things: (1) for a $22 million refund to electric customers in August 1991; (2) that the Company will not request an increase in base rates prior to November 2, 1992 and will 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 June 30, 1993, or until the effective date of new rates, currently anticipated to be July 1, 1993. In addition, the Company has committed to file a new rate case on November 2, 1992.

The second Settlement Agreement established a procedure by which the CPUC can monitor the Company's financial results subject to the CPUC's jurisdiction until new rates become effective in 1993. For monitoring purposes, the CPUC will use the regulatory principles from the Company's last rate case which became effective in May 1984 and a rate of return on regulated equity range of 12.5% to 13.5% as a benchmark against which the Company's future financial performance will be measured.

The third Settlement Agreement resulted in the opening of four new dockets with the CPUC. The first docket, initiated on July 15, 1991, addresses the issues of decoupling the revenues of the Company from its sales, and reviewing and establishing regulatory incentives to encourage demand side management programs (DSM). In regard to DSM programs, the second docket (also opened on July 15, 1991) will examine the potential for DSM investments, the potential of DSM for all customer classes and the implementation of such DSM programs. The third docket, opened October 1, 1991, analyzes "Integrated Resource Planning" taking into account energy demand, supply and environmental matters. On December 2, 1991, the fourth docket was opened to examine low income energy assistance options including, among other issues, costs, eligibility plans, forms of assistance and methods of funding assistance.

Rate adjustments currently in effect
On February 4, 1988, the Company, the OCC and the staff of the CPUC reached an electric rate reduction agreement in response to the Company's earnings being in excess of regulatory authorization. Subsequently, similar reductions were implemented extending until November 27, 1990. As a result, the Company's electric rates were reduced 2.75% from January through March of 1989, 3.19% from April through June of 1989 and 4.29% from July through December of 1989. In 1990, the electric rate reductions were 4.29% from January through April and 1.11% from May to November 27, 1990. In addition, as explained below, beginning on November 27, 1990 and extending through 1991, the Company's electric rates were reduced 1.41%.

As a result of these negotiated rate settlements and in anticipation of the 1992 rate case discussed above, the Company implemented, following CPUC approval, various rate adjustments designed to rectify the earnings imbalance which exists between the electric and gas departments. Such rate adjustments between the electric and gas departments are achieved through a negative 1.41% electric adjustment (discussed above) and a positive 2.77% gas adjustment. These rate adjustments were implemented on November 27, 1990 and will remain in effect until the effective date of new rates pursuant to the rate case discussed above.

As a consequence of the rate reductions and settlements discussed above, electric revenues were reduced by approximately $14.9 million, $24.0 million and $36.0 million for the twelve month periods ending December 31, 1991, 1990 and 1989, respectively. Gas revenues, as a result of the adjustments discussed above, were higher by approximately $13.8 million for the year 1991, when compared to 1990, primarily because there were no corresponding rate adjustments in effect during 1990.

Environmental issues
The Lowry Landfill in southeast metropolitan Denver has been designated by the Environmental Protection Agency (EPA) as a Superfund hazardous waste site pursuant to the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). Under CERCLA, the EPA has notified Potentially Responsible Parties (PRPs) of their potential joint and several liability for the cleanup of the site. The joint and several liability provisions under CERCLA allow the EPA to pursue one or more of the PRPs separately or, at the EPA's option, all the PRPs together. The Company, which had used the site for disposal of trash and neutralized liquids generated in its boiler cleaning process, has been named, along with many others, as a PRP at the Lowry Landfill. The EPA is proceeding with its remedial investigations and feasibility studies at the Lowry Landfill for the purpose of identifying the appropriate methods of cleanup, its attendant cost, and the allocation of the cleanup cost among the various PRPs.

The Company had been actively participating in the Lowry Landfill Generator Group (Group), which monitored the activities of the EPA and its contractors at the Lowry Landfill. The Group became inactive and the bulk of the Company's activities are carried on through the Lowry Landfill De Minimis Group (De Minimis Group) of which the Company is a member. The De Minimis Group was organized as a result of EPA's declaration that it would seek a de minimis settlement at Lowry Landfill. The EPA requested that the PRPs organize themselves to negotiate a settlement for the PRPs whose contribution of waste at the Lowry Landfill is minimal in volume and toxicity. The EPA has published both its final "waste-in" list, which defines the volumetric contributions of the PRPs to the disposal site, and its eligibility criteria for participation in a de minimis settlement. The Company meets the eligibility criteria and will participate in the de minimis settlement.

In September 1991, the EPA submitted a draft Consent Decree to the De Minimis Group and initiated negotiations on the terms and conditions of a settlement. The draft Consent Decree provided for a cleanup cost of $536 million. Under the terms of the draft Consent Decree, the Company's cleanup cost is estimated to range between $1.3 million and $2.7 million.

In November 1991, Chemical Waste Management, Inc. offered to assume all liabilities for, and indemnify and defend the De Minimis Group for a cleanup cost of $500 million. On January 27, 1992, Chemical Waste Management submitted a draft indemnification agreement to the Company. The Company is considering the acceptance of this agreement. Under the terms of this offer, the Company's cleanup cost would be approximately $1.3 million. It is anticipated that the Company will settle its obligation in this matter during the first half of 1992.

Under CERCLA, the EPA has identified and a phase II environmental assessment has revealed 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 will be involved in cleanup of this site as it believes it was a primary contributor. The total project cost is currently estimated to be up to approximately $5 million. Negotiations among the parties will continue into 1992 with cleanup possibly beginning in the spring or summer.

The Company believes that it is probable that costs incurred related to the cleanup of the Lowry Landfill and Barter sites will be recovered through insurance. In addition to these sites, the Company has identified several sites where cleanup of hazardous substances may be required. While settlement costs and potential liability 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. The Company fully intends to pursue the recovery of all costs incurred for such projects through insurance coverage 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.

On November 15, 1990, President Bush signed into law the Clean Air Act Amendments of 1990 aimed at lowering the acidity of rainfall in the United States. 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. The Company will be required to modify certain boilers to reduce NOx emissions.

On October 7, 1988, the results of the Metro Denver Brown Cloud Study, along with a ten point recommendation, were released by the Governor of the State of Colorado. In response, the Company will attempt to reduce SO_2 emissions 50% by applying reduction technology on all of its major metropolitan area generating units and to reduce NOx emissions 20% by modifying those generating units.

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, 1991, the Company had in place long-term contracts for the purchase of coal for existing power plants through 1997 and for the Pawnee Steam Electric Generating Station Proposed Unit 2 from its completion through 2013. The minimum remaining quantities to be purchased under these contracts total 98 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 $818 million at December 31, 1991.

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 19 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 $90 million at December 31, 1991.

Natural gas:
The Company and its regulated subsidiaries have entered into long-term contracts expiring through 2004 for the purchase of natural gas in anticipation of future requirements. In general, purchase prices under these contracts are based on market price formulas. Total estimated obligations, based on current prices, were $619 million at December 31, 1991.

Purchased power:
The Company and Cheyenne have entered into agreements for purchased power to meet system load and energy requirements, to replace generation from Company-owned units under maintenance and outages, and to provide the Company's operating reserve obligation to the Inland Power Pool. These agreements expire on various dates through the year 2025. The price of the energy purchased is determined by contracts, which have been accepted by the FERC, providing generally for recovery by the sellers of their costs. The suppliers under these contracts have obtained financing for their facilities based on such contracts. Total payments associated with such contracts were $170 million (1991), $165 million (1990) and $167 million (1989). The following table shows the fixed portion of commitments under these contracts (payable provided power is available) for each of the next five years and in the aggregate.

	(Thousands of Dollars)
Years ending December 31	
1992	$ 102,599
1993	106,829
1994	169,858
1995	190,141
1996	187,507
1997 and thereafter	2,115,412
Total	$ 2,872,346

In addition, the Company has other long-term purchased power contracts expiring through 2022 that include firm purchase commitments. These contracts similarly provide for recovery by sellers of their costs. Estimated firm commitments (payable provided power is available) under these contracts total $3.4 billion. The estimated total firm commitment amount includes contracts which are expected to be executed as part of the Joint Plan discussed above under Colorado-Ute.

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

Miscellaneous purchases
Commitments made for the purchase of various items of plant and equipment aggregated approximately $213 million at December 31, 1991.

Fort St. Vrain
See Note 2 for certain contingencies relating to Fort St. Vrain.

Customer accounts receivable
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.

The Company has reviewed its customer base for concentrations of credit risk and has determined that no individual customer or group of customers engaged in similar activities represent a material concentration of credit risk to the Company.

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.

8. Employee Benefits

Pensions
The Company and its subsidiaries (excluding Natural Fuels) maintain a noncontributory defined benefit pension plan covering substantially all employees. Effective January 1, 1991, the Board of Directors of the Company approved an amendment that removed the 35 years of credited service limitation in the retirement benefit formula and redefined eligible compensation used in the formula to be based on an employee's highest average compensation during any five years of credited service. Effective December 17, 1991, the Board of Directors of the Company approved an amendment and restatement of the plan. The changes to the plan were generally to comply with the Tax Reform Act of 1986 and did not result in a change in pension benefits.

The Company and its subsidiaries' funding policy is to contribute annually, at a minimum, the amount necessary to satisfy the Internal Revenue Service funding standards. The net pension expense (credit) in 1991, 1990 and 1989 was comprised of:

			(Thousands of Dollars)
	1991	1990	1989
Service cost	**$12,196**	$ 11,441	$ 8,426
Interest cost on projected benefit obligation	**33,322**	31,436	28,569
Loss (return) on plan assets	**(79,467)**	1,773	(74,705)
Amortization of net transition asset at adoption of Statement of Financial Accounting Standards No. 87	**(3,673)**	(3,674)	(3,674)
Other items	**39,807**	(38,726)	39,836
Net pension expense (credit)	**$ 2,185**	$ 2,250	$ (1,548)

Significant assumptions used in determining net periodic pension cost were:

	1991	1990	1989
Discount rate	**8.9%**	8.7%	[illegible]
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, 1991 and 1990, 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)	
	1991	1990
Actuarial present value of benefit obligations:		
Vested	**$ 314,924**	$275,487
Nonvested	**28,543**	23,088
	343,467	298,575
Effect of projected future salary increases	**103,586**	87,333
Projected benefit obligation for service rendered to date	**447,053**	385,908
Plan assets at fair value	**(459,847)**	(392,913)
Excess of plan assets over projected benefit obligation	**12,794**	7,005
Unrecognized net loss	**27,628**	27,550
Prior service cost not yet recognized in net periodic pension cost	**11,672**	12,474
Unrecognized net transition asset at January 1, 1986, being recognized over 17 years	**(40,411)**	(44,084)
Prepaid pension asset	**$ 11,683**	$ 2,945

Significant assumptions used in determining the benefit obligations were:

	1991	1990
Discount rate	**8.2%**	8.9%
Expected long t... increase in compensation level	**5.5%**	5.5%

Postretirement benefits other than pensions

In addition to providing pension benefits, 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. The cost of providing health care and life insurance benefits to active, retired and disabled employees amounted to $33.4 million, $30.4 million and $27.3 million in 1991, 1990 and 1989, respectively. The cost of providing these benefits for retired employees (2,375 in 1991 and 2,338 in 1990) was $8.0 and $7.5 million, respectively. Active and disabled employees' (6,407 in 1991 and 6,709 in 1990) benefit costs were $25.4 and $22.9 million, respectively. The prior year cost for 1989 of providing these benefits for the 2,284 retired employees and the 6,623 active and disabled employees was not separable.

In December 1990, the Financial Accounting Standards Board (FASB) issued SFAS 106 which establishes the accounting and reporting standards for postretirement benefits other than pensions. The statement requires the accrual, during the years that an employee renders service to the Company, of the expected cost of providing postretirement benefits to the employee and the employee's beneficiaries and covered dependents. The statement is effective for fiscal years beginning after December 15, 1992 and the Company and its subsidiaries intend to adopt this statement January 1, 1993.

During 1991, the CPUC approved a rate Settlement Agreement (see Note 7) and the Fort St. Vrain Supplemental Settlement Agreement (see Note 2), both of which address the accounting and regulatory treatment of the costs of postretirement benefits other than pensions. The rate Settlement Agreement stipulates that the Company continue to recover such costs as paid until July 1, 1993, the date new rates are anticipated to be effective. The Fort St. Vrain Supplemental Settlement Agreement stipulates that, effective July 1, 1993, the Company will 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 will include a return on assets that reflects monthly contributions net of benefit payments throughout the year;
- the attribution period will 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 will remain on an as paid basis.

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

Based on an evaluation prepared by the Company's actuary, the postretirement benefit obligation at January 1, 1993, determined as prescribed by the CPUC for the Company, is estimated to range from $125 million to $145 million. The 1993 expense for these benefits is estimated to range between $14 million and $16 million. The life insurance benefit obligation, which will remain on an as paid basis for the Company, determined in accordance with SFAS 106, is estimated to be between $50 million and $60 million. Changes in assumptions such as health care costs, work force demographics or interest rates between now and January 1, 1993 could result in a revision in the estimated obligation and related expense.

Incentive compensation
During 1991, the Company established the Annual and Long-term Incentive Plans (the Incentive Plans) affecting officers and key management employees. Currently, only cash awards are permitted under the Incentive Plans and are based on performance goals tied directly to the Company's financial performance. The Company is seeking shareholder approval of the Omnibus Incentive Plan at the 1992 Annual Shareholders Meeting which will permit the issuance of stock based awards under the Incentive Plans. The Long-term Incentive Plan will allow for the issuance of stock options and restricted shares may be awarded in lieu of a portion of the cash award currently provided by the Annual Incentive Plan. The stock options would be issued at the then fair market value of the Company's common stock and vest over a three year period. During 1991, no amounts were paid under the Incentive Plans.

9. Income Tax Expense

Income tax expense consists of the following:

(Thousands of Dollars)	1991	1990	1989
Current income taxes:			
Federal	**$ 40,156**	$ 40,742	$ 30,174
State	**8,240**	3,931	4,630
	48,396	44,673	34,804
Deferred income taxes (benefits) related to:			
Contributions in aid of construction	**(4,789)**	(3,300)	(11,082)
Accelerated depreciation	**20,721**	23,893	19,064
Net unbilled revenues	**(7,552)**	(2,780)	(14,784)
Fort St. Vrain plant abandonment	**232**	327	42,647
Fort St. Vrain defueling and decommissioning	**12,531**	21,596	8,052
Alternative minimum tax	**2,231**	(5,114)	(2,180)
Other book-tax timing differences	**2,748**	(335)	(4,697)
	26,122	34,287	37,020
Amortization of investment tax credits	**(5,230)**	(4,982)	(5,267)
Total income taxes	**$ 69,288**	$ 73,978	$ 66,557

Deferred tax provisions are not recorded on certain book-tax timing differences. As of December 31, 1991, the cumulative net amount of such timing differences was $348,034,000. The tax effect of this amount is not recorded currently as regulatory commission procedures will result in such costs being charged to customers when the timing differences reverse and the related taxes are paid.

As a result of the Tax Reform Act of 1986, the Company determines its income tax liability to be the greater of regular income tax or AMT. As of December 31, 1991, the Company has an excess cumulative AMT liability over regular tax liability of approximately $5.1 million. This excess becomes a credit which may be applied against future regular tax liabilities.

During June 1989, the Company and its regulated subsidiaries revised their estimate of the deferred taxes to be recognized as a result of taxable customer contributions in aid of construction under the Tax Reform Act of 1986. The recognition of such deferred tax assets for the period January 1, 1987 through June 30, 1989, which had not previously been provided for, reduced 1989 total income tax expense and increased net income by approximately $16.9 million. For financial reporting purposes, deferred tax assets are netted against deferred tax liabilities.

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

	1991		1990		1989 (Thousands of Dollars)	
Tax computed at U.S. statutory rate on pre-tax accounting income	**$74,454**	**34.0%**	$74,842	34.0%	$73,235	34.0%
Increase (decrease) in tax from:						
Difference between tax and book depreciation	**(451)**	**(0.2)**	(1,215)	(0.5)	1,067	0.5
Allowance for funds used during construction	**(2,767)**	**(1.3)**	(2,122)	(1.0)	(1,226)	(0.6)
Amortization of investment tax credits	**(5,095)**	**(2.3)**	(5,195)	(2.4)	(5,378)	(2.5)
State income taxes, net of federal income tax benefit	**5,431**	**2.5**	2,588	1.2	3,060	1.4
Customer contributions in aid of construction	**1,113**	**0.5**	1,321	0.6	(7,794)	(3.6)
Capitalized software, net of amortization	**(5,533)**	**(2.5)**	(3,678)	(1.7)	(2,390)	(1.1)
Fort St. Vrain plant abandonment	**214**	**0.1**	548	0.3	10,908	5.1
Fort St. Vrain defueling and decommissioning	**1,441**	**0.6**	3,802	1.7	1,277	0.6
Net unbilled revenues	**(735)**	**(0.3)**	(1,020)	(0.5)	(2,178)	(1.0)
Other–net	**1,216**	**0.5**	4,107	1.9	(4,024)	(1.9)
Total income taxes	**$69,288**	**31.6%**	$73,978	33.6%	$66,557	30.9%

On February 11, 1992, the FASB issued Statement of Financial Accounting Standards No. 109 - "Accounting for Income Taxes" (SFAS 109), which supersedes Statement of Financial Accounting Standards No. 96 - "Accounting for Income Taxes." This statement is effective for fiscal years beginning after December 15, 1992. SFAS 109 establishes new financial accounting and reporting standards to recognize tax liabilities and assets that result from an enterprise's activities during the current and preceding years. The Company is currently analyzing the provisions of SFAS 109 and the Company believes application of the new standard will not have a material adverse financial impact.

10. Supplementary Income Statement Information

	1991	1990	1989 (Thousands of Dollars)
Taxes (other than income taxes):			
Real estate and personal property taxes	**$43,746**	$41,307	$39,567
Social security taxes	**20,398**	19,951	18,237
City and state use taxes	**8,397**	8,625	7,540
Miscellaneous taxes	**7,045**	5,823	6,324
	$79,586	$75,706	$71,668
Charged:			
Directly to income:			
Operating expenses	**$74,335**	$70,033	$67,430
Other	**138**	124	129
To property, plant and equipment and various other accounts	**5,113**	5,549	4,109
	$79,586	$75,706	$71,668

11. Segments of Business

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	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				599,372
				$3,472,789

Segment information for the year ended December 31, 1990 is as follows:

(Thousands of Dollars)

	Electric	Gas	Other	Total
Operating revenues	$1,145,915	$561,712	$ 26,312	$1,733,939
Operating expenses, excluding depreciation and income taxes	806,287	5[illegible]1,415	5,326	1,315,028
Depreciation	79,95[illegible]	23,6[illegible]	2,908	106,527
Total operating expenses*	886,23[illegible]	527,084	8,234	1,421,555
Operating income*	$ 259,[illegible]	$ 34,6[illegible]	$ 18,078	$ 312,384
Plant construction expenditures**	$ 150,780	$105,233	$ 5,208	$ 261,221
Identifiable assets, December 31, 1990:				
Property, plant and equipment**	$1,939,301	$569,108	$100,852	$2,609,261
Materials and supplies	$ 60,404	$ 11,486	$ 29	71,919
Fuel inventory	$ 33,219	$ –	$ 208	33,427
Gas in underground storage	$ –	$ 13,701	$ –	13,701
Other corporate assets				514,764
				$3,243,072

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

Segment information for the year ended December 31, 1989 is as follows:

				(Thousands of Dollars)
	Electric	**Gas**	**Other**	**Total**
Operating revenues	$1,139,471	$577,282	$23,913	$1,740,666
Operating expenses, excluding depreciation and income taxes	813,128	511,123	829	1,325,080
Depreciation	78,658	20,849	3,324	102,831
Total operating expenses*	891,786	531,972	4,153	1,427,911
Operating income*	$ 247,685	$ 45,310	$19,760	$ 312,755
Plant construction expenditures**	$ 112,750	$ 54,135	$ 7,533	$ 174,418
Identifiable assets, December 31, 1989:				
Property, plant and equipment**	$1,886,444	$488,592	$93,107	$2,468,143
Materials and supplies	$ 66,857	$ 10,045	$ 35	76,937
Fuel inventory	$ 34,251	$ –	$ 117	34,368
Gas in underground storage	$ –	$ 16,092	$ –	16,092
Other corporate assets				458,899
				$3,054,439

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

12. 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. Other operating leases have various terms and may be renewed or replaced. Rental expense for 1991, 1990 and 1989 was $21.7 million, $18.4 million and $11.0 million, respectively. At December 31, 1991, future minimum rental payments applicable to noncancelable operating leases were as follows:

	(Thousands of Dollars)
Years ending December 31	
1992	$ 23,220
1993	23,099
1994	17,837
1995	11,891
1996	9,323
1997 and thereafter	48,440
Total minimum rental payments	$133,810

13. Quarterly Financial Data (Unaudited)

The following summarized quarterly information for 1991 and 1990 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)

1991 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues	$550,843	$390,723	$379,693	$473,645
Operating income	$ 69,447	$ 35,763	$ 58,114	$ 80,254
Net income	$ 45,093	$ 12,212	$ 34,340	$ 58,048
Earnings available for common stock	$ 42,017	$ 9,136	$ 31,282	$ 55,024
Weighted average common shares outstanding	54,746	55,267	55,721	56,152
Earnings per weighted average common share	$0.77	$0.16	$0.56	$0.99

(Thousands–except per share data)

1990 Three Months Ended	March 31	June 30	September 30	December 31
Operating revenues [1]	$513,322	$418,669	$364,380	$437,568
Operating income	$ 66,197	$ 52,622	$ 57,114	$ 62,473
Net income	$ 42,289	$ 30,188	$ 34,259	$ 39,408
Earnings available for common stock [2]	$ 39,162	$ 27,061	$ 31,149	$ 36,332
Weighted average common shares outstanding	53,072	53,440	53,802	54,188
Earnings per weighted average common share [2]	$0.74	$0.51	$0.58	$0.67

[1] For the year 1990, operating revenues and gas purchased for resale expense for the three months ended March 31, June 30 and September 30 have been restated to reflect a revision in the treatment of gas refunds received from suppliers. These revisions had no effect on income.

[2] Due to rounding, quarterly figures do not add to annual total.

Dividends

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

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

Shareholders of record receive dividends directly from the company unless such shareholder has elected to reinvest dividends through the company's Dividend Reinvestment Plan (DRP) or has authorized direct deposit of dividends to a financial institution.

Dividend Reinvestment Plan

The company's DRP provides an opportunity for holders of the company's common stock to acquire additional shares of such stock in a convenient and economical manner. Participants in the Plan may reinvest cash dividends on all or a portion of their shares of common stock and/or make optional cash payments.

Stock Trading

The company's common stock ($5 par value) is listed for trading on the New York, Midwest and Pacific Stock Exchanges under the ticker symbol "PSR". Quotes may be obtained in daily newspapers where the common stock is listed as "PSvCol" in the New York Stock Exchange listing table.

Three series of cumulative preferred stock are actively traded: 4 1/4 % ($100 par value) on the American Stock Exchange; 7.15% ($100 par value) on the New York Stock Exchange; and 8.40% ($25 par value) on the New York Stock Exchange and Boston Stock Exchange. All other series are not actively traded and market prices are not published.

Transfer Agent

The company is the sole transfer agent and registrar for its common and preferred stock.

Annual Meeting

The annual meeting of shareholders will be held at 2:00 p.m. on May 5, 1992, at the Radisson Hotel, Grand Ballroom, Lobby Level, 1550 Court Place, Denver, Colorado.

Shareholders' Inquiries and Assistance

Shareholders desiring assistance with lost or stolen stock certificates or dividend checks, name changes, address changes, stock transfers, information on the DRP, or other matters should call the Shareholder Services Department. The following telephone numbers are available during business hours, 7:30 a.m. to 5:00 p.m. (MST).

Denver Metro Area	(303) 294-2566
Toll-Free Number	(800) 635-0566

Written communication should be addressed to:

Public Service Company of Colorado
Shareholder Services
P.O. Box 840, Suite 300
Denver, Colorado 80201-0840

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 56

Collis P. Chandler, Jr.
Denver, CO (1985)
President
Chandler & Associates, Inc.
Age 65

Doris M. Drury, PhD
Denver, CO (1975)
Regis College
Executive Director,
MBA program
President, Center for Business
and Economic Forecasting, Inc.
Age 65

Thomas T. Farley
Pueblo, CO (1983)
Attorney at Law
Petersen & Fonda
Professional Corp.
Age 57

Gayle L. Greer
Denver, CO (1986)
Vice President,
American Television
and Communications
Corporation
Age 50

A. Barry Hirschfeld
Denver, CO (1988)
President, A. B. Hirschfeld
Press, Inc.
Age 49

George B. McKinley
Evanston, WY (1976)
President
First McKinley Corp.
Age 64

Will F. Nicholson, Jr.
Denver, CO (1981)
Chairman of the Board
and President
Colorado National
Bankshares, Inc.
Age 62

J. Michael Powers
Cheyenne, WY (1978)
President, Powers Brick and Tile
and Powers Products Co.
Age 49

Thomas E. Rodriguez
Denver, CO (1986)
President, Thomas E. Rodriguez
& Associates, P.C.
Age 47

Rodney E. Slifer
Vail, CO (1986)
Partner
Slifer, Smith & Frampton
Age 57

W. Thomas Stephens
Denver, CO (1989)
Chairman, President, and
Chief Executive Officer
Manville Corporation
Age 49

Robert G. Tointon
Greeley, CO (1988)
President
Phelps-Tointon, Inc.
Age 58

( ) Year elected to the
Board of Directors

Ages as of December 31, 1991

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
Collis P. Chandler, Jr.
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 56 (29)

Clark B. Ewald
Senior Vice President
Customers
Age 57 (32)

Richard C. Kelly
Senior Vice President
Finance and Administration
Chief Financial Officer
Age 45 (23)

Patrick W. McCarter
Senior Vice President
Electric Operations
Age 54 (32)

James R. McCotter
Senior Vice President,
General Counsel and
Corporate Secretary
Age 48 (16)

A. E. Middents
Senior Vice President
Gas Operations
Age 53 (31)

A. C. Crawford
Vice President
Electric Production
Age 59 (2)

Dale V. Fetchenhier
Vice President
Information Technology
and Services
Age 58 (34)

Ross C. King, Jr.
Vice President
Metropolitan Customer
Operations
Age 50 (25)

William J. Martin
Vice President
Electric Engineering
and Planning
Age 60 (34)

Earl E. McLaughlin, Jr.
Vice President
Marketing, Customer Services
and Support Services
Age 51 (31)

James H. Ranniger
Vice President
Rates and Regulations
Age 55 (33)

Philip D. Shaffer
Vice President
Division Customer Operations
Age 46 (18)

Marilyn E. Taylor
Vice President
Administrative Services
Age 49 (4)

Ralph Sargent III
Treasurer
Age 42 (13)

Other Officers

W. Wayne Brown
Assistant Secretary
and Controller
Age 41 (19)

Anthony J. DeNovellis
Assistant Secretary and Auditor
Age 43 (21)

George P. Green
Assistant Secretary
Age 55 (29)

Carol J. Peterson
Assistant Secretary
Age 49 (5)

J. Anthony Terrell
Assistant Secretary and
Assistant Treasurer
Age 48 (1)

Stephen H. Whitcomb
Assistant Secretary
Age 41 (16)

Richard L. Hunt
Assistant Treasurer
Age 49 (25)

Larry D. Hall
Assistant Treasurer
Age 36 (10)

William E. Lewis
Assistant Treasurer
Age 42 (20)

Managers, Geographic Divisions

Joseph Augustine,
Denver Metropolitan
Age 45 (21)

Bill L. Croley
Southern
Age 57 (19)

David P. Davia
Boulder
Age 46 (23)

Michael J. Geile
Home Light
Age 49 (27)

W. Bruce Hansford
Front Range
Age 50 (23)

Kenneth L. Headrick
Northern
Age 52 (31)

Douglas C. Lockhart
Western
Age 49 (27)

Joseph O. Marquez
San Luis Valley
Age 54 (31)

Phillip L. Noll
Mountain
Age 52 (33)

Lawrence F. Petrini
Southeast Metropolitan
Age 61 (36)

George A. Senkus
Southwest Metropolitan
Age 55 (24)

Peter West
North Metropolitan
Age 42 (19)

Presidents Subsidiary Companies

D. D. Hock
Bannock Center Corporation
1480 Welton, Inc.
Green and Clear Lakes Company
P.S. Colorado Credit Corporation
P.S.R. Investments, Inc.
Age 56 (29)

A. E. Middents
Fuel Resources Development Co.
Western Gas Supply Company
Age 53 (31)

Philip D. Shaffer
Cheyenne Light, Fuel
and Power Company
Age 46 (18)

Thomas E. Moore
Natural Fuels Corporation
Age 30 (1)

Other Principal Subsidiary Officers

Richard E. Braun
Executive Vice President
and Chief Operating Officer
Fuel Resources Development Co.
Age 62 (2)

Linn T. Leeburg
Executive Vice President
and Chief Operating Officer
Western Gas Supply Company
Age 49 (25)

Legal Counsel

Kelly, Stansfield & O'Donnell
Denver, Colorado

Auditors

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

Transfer Agents and Registrars for all Issues of Capital Stock Principal Transfer Agent, Dividend Paying Agent, Dividend Reinvestment Plan Agent, Registrar

Public Service Company
of Colorado
Denver, Colorado

( ) Denotes years of service or
association with the Company
through December, 1991

Ages as of December 31, 1991

Public Service
Company of Colorado

P.O. Box 840
Denver, Colorado 80201-0840
(303) 571-7511

Shareholder Information

(800) 835-0566