Form 10-K

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

[✓] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 1996
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to _______________
Commission file number 1-3280

Public Service Company of Colorado

(Exact name of registrant as specified in its charter)

Colorado	**84-0296600**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1225 17th Street, Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant's Telephone Number, including area code: (303) 571-7511

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $5 per share	New York, Chicago and Pacific
Rights to Purchase Common Stock	New York, Chicago and Pacific
Cumulative Preferred Stock, par value $100 per share	
4 1/4 Series	American
7.15% Series	New York
Cumulative Preferred Stock ($25), par value per share	
8.40% Series	New York

Securities Registered Pursuant to Section 12(g) of the Act:
Cumulative Preferred Stock, par value $100 per share
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of the registrant's Common Stock, $5.00 par value (the only class of voting stock), held by non-affiliates was $2,536,745,052 based on the last sale price thereof reported on the consolidated tape for February 21, 1997.

At February 21, 1997, 65,253,892 shares of the registrant's Common Stock, $5.00 par value (the only class of common stock), were outstanding.

M004

Documents Incorporated by Reference

Portions of the registrant's 1997 Proxy Statement are incorporated by reference in Part II, Item 9 and Part III, Items 10, 11, 12 and 13 of this Form 10-K.

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Attention

ENCLOSED IS THE PUBLIC SERVICE COMPANY OF COLORADO'S 1996 FORM 10-K WHICH PROVIDES AN IN-DEPTH OPERATIONAL AND FINANCIAL REVIEW OF THE COMPANY. IN LIGHT OF THE ANTICIPATED TIMING OF MERGER COMPLETION, THE 10-K IS BEING PROVIDED IN LIEU OF THE CUSTOMARY ANNUAL REPORT TO SHAREHOLDERS THIS YEAR.

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PART III

In addition to the historical information contained herein, this report contains a number of "forward-looking statements", within the meaning of the Securities Exchange Act of 1934. Such statements address future events and conditions concerning capital expenditures, resolution and impact of litigation, regulatory matters, liquidity and capital resources, and accounting matters. Actual results in each case could differ materially from those projected in such statements due to a variety of factors including, without limitation, restructuring of the utility industry; future economic conditions; earnings retention and dividend payout policies; developments in the legislative, regulatory and competitive environments in which the Company operates; and other circumstances that could affect anticipated revenues and costs, such as compliance with laws and regulations. These and other factors are discussed in the Company's filings with the Securities and Exchange Commission including this report.

TERMS

The abbreviations or acronyms used in the text and notes are defined below:

Abbreviation or Acronym	Term
AEP	American Electric Power
AFDC	Allowance for Funds Used During Construction
APB Opinion No. 25	Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees"
Amax	Amax Coal Company, a subsidiary of Cyprus/Amax Coal Company
Arapahoe	Arapahoe Steam Electric Generating Station
BLM	Bureau of Land Management
Cameo	Cameo Steam Electric Generating Station
CCT3	Clean Coal Technology III
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Cherokee	Cherokee Steam Electric Generating Station
Cheyenne	Cheyenne Light, Fuel and Power Company
COLI	Corporate-owned life insurance
Colorado Supreme Court	Supreme Court of the State of Colorado
Comanche	Comanche Steam Electric Generating Station
Company or PSCo	Public Service Company of Colorado (excluding subsidiaries)
CPCN	Certificate of Public Convenience and Necessity
CPUC	Public Utilities Commission of the State of Colorado
Craig	Craig Steam Electric Generating Station
CWIP	Construction Work in Progress
CWQCD	Colorado Water Quality Control Division
Denver District Court	District Court in and for the City and County of Denver
DOE	U.S. Department of Energy
DSM	Demand Side Management
DSMCA	Demand Side Management Cost Adjustment
Dth	Dekatherm
e prime	e prime, inc.
ECA	Energy Cost Adjustment
EIS	Environmental Impact Statement
EPAct	National Energy Policy Act of 1992
EPA	U.S. Environmental Protection Agency
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FERC Order 636	FERC Order Nos. 636-A and 636-B
Fort St. Vrain	Fort St. Vrain Nuclear Electric Generating Station
Fuelco	Fuel Resources Development Co., a dissolved Colorado corporation
GCA	Gas Cost Adjustment
Hayden	Hayden Steam Electric Generating Station
IBM	IBM Global Services
ICA	Incentive Cost Adjustment
Interstate	Colorado Interstate Gas Company
IPPF	Independent Power Production Facility
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
KN Energy	KN Energy, Inc.

Merger	the proposed business combination between the Company and SPS
Merger Agreement	Agreement and Plan of Reorganization by and among the Company, SPS, and NCE, as amended
Natural Fuels	Natural Fuels Corporation
NCE	New Century Energies, Inc.
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
OCC	Colorado Office of Consumer Counsel
OPEB	Other Postretirement Employee Benefits
PCB	Polychlorinated biphenyl
Pawnee	Pawnee Steam Electric Generating Station
Pawnee 2	Pawnee Steam Electric Generating Station, Unit 2 (proposed)
Pool	Inland Power Pool
PRPs	Potentially Responsible Parties
PSCCC	PS Colorado Credit Corporation
PSRI	PSR Investments, Inc.
PUHCA	Public Utility Holding Company Act of 1935
QF	Qualifying Facility
QFCCA	Qualifying Facilities Capacity Cost Adjustment
QSP	Quality of Service Plan
SEC	Securities and Exchange Commission
SFAS 71	Statement of Financial Accounting Standards No. 71 - "Accounting for the Effects of Certain Types of Regulation"
SFAS 106	Statement of Financial Accounting Standards No. 106 - "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 107	Statement of Financial Accounting Standards No. 107 - "Disclosures about Fair Value of Financial Instruments"
SFAS 109	Statement of Financial Accounting Standards No. 109 - "Accounting for Income Taxes"
SFAS 112	Statement of Financial Accounting Standards No. 112 - "Employers' Accounting for Postemployment Benefits"
SFAS 121	Statement of Financial Accounting Standards No. 121 - "Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed Of"
SFAS 123	Statement of Financial Accounting Standards No. 123 - "Accounting for Stock-Based Com[illegible]tion"
SO_2	Sulfu[illegible]de
SPS	Southwestern Public Service Company
TOG	Texas-Ohio Gas, Inc.
TOP	Texas-Ohio Pipeline, Inc.
Tri-State	Tri-State Generation and Transmission Association, Inc.
UK	United Kingdom
Valmont	Valmont Steam Electric Generating Station
WGG	WestGas Gathering, Inc.
WGI	WestGas InterState, Inc.
WGT	WestGas TransColorado, Inc.
WPSC	Public Service Commission of Wyoming
WSCC	Western Systems Coordinating Council
Young Storage	Young Gas Storage Company, Ltd.
YGSC	Young Gas Storage Company
Yorkshire Electricity	Yorkshire Electricity Group plc
Yorkshire Holdings	Yorkshire Holdings plc
Yorkshire Power	Yorkshire Power Group Ltd.
Zuni	Zuni Steam Electric Generating Station

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PART I

Item 1. *Business*

The Company

The Company, incorporated through merger of predecessors under the laws of the State of Colorado in 1924, is an operating public utility engaged, together with its subsidiaries, principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transmission, distribution, sale and transportation of natural gas. The Company provides electricity or gas or both in an area having an estimated population of 3.0 million people of which approximately 2.1 million are in the Denver metropolitan area. The Company's operations are wholly within the State of Colorado.

On August 22, 1995, the Company, SPS, a New Mexico corporation, and NCE, a newly formed Delaware corporation, entered into a Merger Agreement providing for a business combination as peer firms involving the Company and SPS in a "merger of equals" transaction. As part of the agreement, NCE would become the parent company for the Company and SPS. On January 30, 1996, NCE filed its application with the SEC to be a registered public utility holding company. The shareholders of the Company and SPS approved the Merger Agreement on January 31, 1996. The Merger is subject to customary closing conditions, including the receipt of all necessary governmental approvals and the making of all necessary governmental filings, as discussed in Note 3. Merger and Note 9. Commitment and Contingencies - Regulatory Matters in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA. The future operations and financial position of the Company will be significantly affected by the Merger. See the information in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and the unaudited pro forma financial information for NCE included in this report Exhibit 99.

On February 24, 1997, the Company and AEP jointly announced that they have reached agreement with the board of directors of Yorkshire Electricity, a UK regional electricity company, on the terms of a recommended cash tender offer for all of the outstanding and to be issued ordinary shares of Yorkshire Electricity (the "Proposed Acquisition"). The Company and AEP, through a joint venture named Yorkshire Holdings, are offering the equivalent of US $15.02 (9.27 pounds) per ordinary share, for a total purchase price of approximately US $2.4 billion (1.5 billion pounds). The boards of directors of the Company and AEP have approved the transaction. The board of directors of Yorkshire Electricity has agreed to recommend the offer to Yorkshire Electricity's shareholders. Consummation of the Proposed Acquisition is subject to customary conditions in the UK, including regulatory clearance and acceptance of the offer by holders of at least 90% of the outstanding shares of Yorkshire Electricity. Yorkshire Holdings may waive the latter condition when it has received acceptances of its offer and has otherwise acquired shares which in total represent more than 50% of the outstanding shares of Yorkshire Electricity. The Company cannot predict at this time whether or not these conditions will be met or waived.

See "Recent Developments" in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and Note 4. Acquisition and Divestiture of Investments - Proposed Acquisition of Yorkshire Electricity in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

As of December 31, 1996, the Company owned all of the outstanding capital stock of Cheyenne, WGI, e prime, 1480 Welton, Inc., PSRI, PSCCC, Green and Clear Lakes Company and Fuelco (a dissolved corporation). In addition, the Company owned 83.63% of the capital stock of Natural Fuels and e prime owned all of the outstanding capital stock of TOG, TOP and YGSC. These subsidiaries are included in the Company's consolidated financial statements. The Company also holds a controlling interest in several other relatively small ditch and water companies whose capital requirements are not significant and which are not consolidated in the Company's financial statements or statistical data.

Information regarding industry segments is set forth in Note 14. Segments of Business in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Cheyenne and WGI

Cheyenne is an operating utility engaged in the purchase, distribution and sale of electricity and natural gas primarily serving customers in Cheyenne, Wyoming. WGI is a natural gas transmission company engaged in transporting gas to Cheyenne, Wyoming via a thirteen mile connecting pipeline between Chalk Bluffs, Colorado and Cheyenne, Wyoming. Gas transportation volumes were approximately 3.4 million Dth for 1996.

e prime and subsidiaries

e prime, with headquarters in Denver and an office in Tulsa, was established in 1995 and provides energy related products and services which include, but are not limited to, electric and gas brokering and marketing, energy consulting and project development services and information processing and other technology based services. e prime is also pursuing international energy investment opportunities. On March 29, 1996, e prime received authorization from the FERC to act as a power marketer. Effective September 1, 1996, the Company and e prime acquired TOG, a gas marketing company, with headquarters in Houston and an office in Boston. TOG serves approximately 1,400 industrial and commercial customers in the eastern U.S. e prime and TOG have merged operations and together they provide value-added energy related products and services to end use customers and utilities nationwide. e prime also acquired TOP on September 1, 1996, a small pipeline company which connects two major interstate pipelines. TOP is subject to FERC regulation. The Company and its subsidiary, e prime are also developing the necessary policies and procedures to enable it to use energy derivative financial instruments in its electric and gas brokering and marketing activities.

e prime owns a 50% general partnership interest in the Johnstown Cogeneration Company, LLC, which produces electric energy that is sold to PSCo under a 30 year contract. In addition, e prime acquired a 50% limited partnership interest in ep3 to identify and develop various international energy business opportunities.

YGSC, a subsidiary of e prime, owns a 47.5% general partnership interest in Young Storage. Young Storage owns and operates an underground gas storage facility in northeastern Colorado. Young Storage is subject to FERC regulation.

Other Subsidiaries

1480 Welton, Inc. is a real estate company which owns certain of the Company's real estate interests; PSRI owns and manages permanent life insurance policies on certain past and present employees, the benefits from which are to provide future funding for general corporate purposes; PSCCC is a finance company that finances certain of the Company's current assets; Green and Clear Lakes Company owns water rights and storage facilities for water used at the Company's Georgetown Hydroelectric Station; Natural Fuels sells compressed natural gas as a transportation fuel to retail markets, converts vehicles for natural gas usage, constructs fueling facilities and sells miscellaneous fueling facility equipment. On July 1, 1996, Fuelco, which was primarily involved in the exploration and production of oil and natural gas, sold its remaining properties, the San Juan Basin Coal Bed Methane properties, at approximately book value. Effective October 31, 1996, Fuelco was dissolved. (See Note 4. Acquisition and Divestiture of Investments in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Electric Operations

The Company proposes to use the following resources to meet its net dependable system capacity: 1) the Company's electric generating stations (see Electric Generation Property in Item 2. PROPERTIES); 2) purchases from other utilities and from QFs and IPPFs; 3) demand-side management options and 4) new generation alternatives, including the phased repowering of Fort St. Vrain. Additional planned resources are summarized in

the Company's proposed IRP, which was filed with the CPUC in October 1996 (see "Regulation and Rates - State Regulation - IRP - Electric").

Peak Load

During 1997, net firm system peak demand for the Company and Cheyenne is estimated to be 4,413 Mw, assuming normal weather conditions. Net dependable system capacity is projected to be, after accounting for 68 Mw of demand-side management options, 5,127 Mw (generating capacity of 3,304 Mw and firm purchases of 1,823 Mw) at the time of the anticipated 1997 system peak (summer season), resulting in a reserve margin of approximately 16%.

The net firm system peak demand for the Company and Cheyenne for each of the last five years was as follows:

	1992	1993	1994	1995	1996
Net Firm System Peak Demand* (Mw).........	3,757	3,869	3,972	4,248	4,397

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* Excludes station housepower, nonfirm electric furnace load and controlled interruptible loads (of which approximately 156 Mw, 164 Mw, 160 Mw, 148 Mw and 122 Mw in the years 1992-1996, respectively, was not interrupted at the time of the system peak).

The net firm system peak demand for the Company and Cheyenne for the years 1992-1996 occurred in the summer. The net firm system peak demand for 1996, which occurred on August 13, 1996, was 4,397 Mw. At that time, the net dependable system capacity totaled 5,103 Mw (generating capacity of 3,314 Mw, together with firm purchases of 1,789 Mw), which represented a reserve margin of approximately 16%. Net dependable system capacity is the maximum net capacity available from both Company-owned generating units and purchased power contracts to meet the net firm system peak demand.

Purchased Power

The Company purchases capacity and energy from various regional utilities as well as QFs and an IPPF in order to meet the energy needs of its customers. Capacity, typically measured in Kws or Mws, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in Kwhs or Mwhs, is a measure of the amount of electricity produced from a particular generating source over a period of time. Purchase power contracts typically provide for a charge for the capacity from a particular generating source, together with a charge for the associated energy actually purchased from such generating source.

The Company and Cheyenne have contracted with the following sources for the firm purchase of capacity and energy at the time of the anticipated summer 1997 net firm system peak demand through the expiration of the contracts:

Company	Generating Source	Mw Contracted For at the Time of the Anticipated Summer 1997 Net Firm System Peak Demand	Contract Expiration
Basin Electric Power Cooperative, Agreements 1 and 2 (a) (b)	Laramie River Station Units 2 and 3	175	2016
PacifiCorp (c)	PacifiCorp System	140	2000
PacifiCorp (d)	PacifiCorp Resource Pool	176	2011
Platte River Power Authority (a) (e)	Craig Units 1 and 2; Rawhide Unit 1	180	2004
Tri-State		525	(f)
Agreements 1, 2, 3 and 4 (a) (f)	Laramie River Station Units 2 and 3; Craig Units 1, 2 and 3		
Agreement 5 (a) (f)	Laramie River Station Units 2 and 3; Craig Units 1, 2 and 3; Nucla Units 1, 2, 3 and 4		
Various Owners (a)	QFs & IPPF	627	Various dates
		1,823	

(a) These contracts are contingent upon the availability of the units listed as the generating source. These contracts are take and pay contracts. Based upon the terms of these agreements, if the capacity is available from these units, the Company is obligated to pay for capacity whether or not it takes any energy. However, the Company has historically satisfied the minimum energy requirements associated with these agreements and anticipates doing so in the future. Additionally, if these units are unavailable, the supplying company has no obligation to furnish capacity or energy and the capacity charge to the Company is reduced accordingly.

(b) The Company has entered into two agreements with Basin Electric Power Cooperative. The first agreement is for 100 Mw of capacity through March 31, 2016. The second agreement is for 75 Mw of summer season capacity through March 31, 2016 and 25 Mw of winter season capacity through March 31, 2010.

(c) This contract calls for PacifiCorp to sell to Cheyenne the total electric capacity and energy requirements associated with the operation of Cheyenne's service area.

(d) The current agreement with PacifiCorp expires October 31, 2022. However, the agreement provides the Company the opportunity to exercise an irrevocable option to terminate the agreement on December 31, 2011, provided the Company gives notice to PacifiCorp no later than March 1, 2002.

(e) The amount of capacity to be made available for each summer and winter season is agreed upon prior to such season to the extent that Platte River Power Authority has excess capacity for such season.

(f) The Company has entered into five agreements with Tri-State. Agreements 1, 2 and 5 are contracts for 100 Mw each of capacity and expire in 2001, 2017 and 2011, respectively. Agreement 3 is a contract for 25 Mw of summer season capacity and 75 Mw of winter season capacity and expires in 2016. Agreement 4 expires in 2018 and the related capacity is for the following amounts: 1997 through 2000 - 200 Mw and 2001 through 2018 - 250 Mw; however, either party may elect to reduce the Agreement 4 capacity by up to 50 Mw each year, except for 2001, effective in the year 1999. If the full 50 Mw reduction is taken each year, the capacity associated with Agreement 4 from 1999 on would be as follows: 1999 - 150 Mw, 2000 through 2001 - 100 Mw, 2002 - 50 Mw with no commitments thereafter. The Company has notified Tri-State of its intent to reduce the capacity associated with Agreement 4 to 150 Mw for 1999.

See Note 9. Commitments and Contingencies - Purchase Requirements in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA for information regarding the Company's financial commitments under these contracts. See Electric Transmission and Distribution Property in Item 2. PROPERTIES for a discussion of the Company's interconnections with these sources.

Based on present estimates, the Company and Cheyenne will purchase approximately 37% of the total electric system energy input for 1997. In addition, based on the capacity associated with the purchase power contracts described above, approximately 36% of the total net dependable system capacity for the estimated summer 1997 net firm system peak demand for the Company and Cheyenne will be provided by purchased power, compared to approximately 35% in 1996.

In accordance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Company is obligated to purchase at "avoided cost" capacity and energy from QFs. The Company has had tariffs in effect since 1984 for these purchases.

In December 1987, the CPUC issued an order imposing a moratorium during which the Company was no longer required to continue to execute additional QF contracts due to the fact that excess generating capacity would be created if additional contracts were executed. Although a comprehensive QF bidding procedure was adopted by the CPUC in 1988, which allowed the Company to purchase the most competitively priced QF power, all of the QF capacity purchased by the Company, including approximately 5 Mw of additional capacity scheduled to come on line in the future, is being purchased under contracts entered into prior to the adoption of such procedure. Based on the 1988 comprehensive QF bidding criteria, QFs could provide up to 20% of the Company's net firm system peak load. The CPUC has circulated proposed new rules that would supplant the 1988 comprehensive QF bidding criteria whereby long-term future resource needs would be selected through a competitive bidding process. In 1996, approximately 15% of the Company's summer net firm system peak demand was provided by QFs.

In addition to long-term and QF and IPPF purchases, the Company also made short-term and non-firm purchases throughout the year to replace generation from Company owned units which were unavailable due to maintenance and unplanned outages, to provide the Company's reserve obligation to the Pool, to obtain energy at a lower cost than that which could be produced by other resource options, including Company-owned generation and/or long-term purchase power contracts, and for various other operating requirements. Short-term and non-firm purchases accounted for approximately 3% of the Company's total energy requirement in 1996.

Based on current projections, the Company expects that purchased capacity will continue to meet a significant portion of system requirements at least for the remainder of the 1990s. Such purchases neither require the Company to make an investment nor afford the Company an opportunity to earn a return. Further discussion related to recovery of purchased capacity costs can be found in "Regulations and Rates - State Regulation - Electric and Gas Adjustment Clauses".

The Company is a member of the Pool which is composed of members each of which owns and/or operates electric generation and/or transmission systems which are interconnected to one or more other member systems. The objective of the Pool is to provide capacity which is categorized as: 1) immediately accessible; 2) accessible within ten minutes; and 3) accessible within twelve hours, as required. As a result of membership in the Pool, the Company can supply and protect its electric system with less aggregate operating reserve capacity than otherwise would be necessary; emergency conditions can be met with less likelihood of curtailment or impairment of electric service; and generation and transmission facilities and interconnections can be used more efficiently and economically.

Construction Program

At December 31, 1996, the Company and its subsidiaries estimated the cost of their total construction program, including AFDC, to be approximately $327 million in 1997, approximately $376 million in 1998, and

approximately $300 million in 1999 (see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS).

Electric Fuel Supply

The following table presents the delivered cost per million Btu of each category of fuel consumed by the system for electric generation of the Company and its utility subsidiary during the years indicated, the percentage of total fuel requirements represented by each category of fuel and the weighted average cost of all fuels during such years:

	Coal*		Gas		Weighted Average All Fuels**
	Cost $	%	Cost $	%	Cost $
1996	1.029	98	2.424	2	1.054
1995	0.992	99	1.521	1	0.998
1994	1.038	99	2.069	1	1.053
1993	1.078	98	2.319	2	1.097
1992	1.091	99	2.065	1	1.105

* The average cost per ton of coal, including freight, for years 1992 through 1996 shown above was $21.14, $21.03, $20.57, $19.06 and $20.17, respectively.

** Insignificant purchases of oil are included.

Coal

The Company's primary fuel for its steam electric generating stations is low-sulfur western coal. The Company's coal requirements are purchased primarily under seven long-term contracts with suppliers operating in Colorado and Wyoming, the largest of which is with Cyprus/Amax Coal Company, which operates the Belle Ayr and Eagle Butte Mines near Gillette, Wyoming and the Foidel Creek and Empire Energy mines in northwestern Colorado.

Long-term contracts presently in existence provide for a substantial portion of future annual coal requirements. Any shortfall will be provided by purchases on the spot market. During the year ended December 31, 1996, the Company's coal requirements for existing plants were approximately 9,118,360 tons, a substantial portion of which was supplied pursuant to long-term supply contracts. Coal supply inventories at December 31, 1996 were approximately 43 days usage, based on the average peak burn rate for all the Company's coal-fired plants.

The following table provides a summary of the basic supply provisions of the existing long-term contracts, which provide a minimum delivery of approximately 78 million tons of low-sulfur coal over their remaining life (see Note 9. Commitments and Contingencies - Purchase Requirements in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Coal Supplier and Delivery Year	Minimum delivery per contract year in tons	Maximum delivery per contract year in tons	Contract maximum sulfur content
Amax (1)			
1988 through Pawnee 2 completion	3,960,000	(2)	0.50%
Pawnee 2 completion through 2013	3,600,000	(3)	0.50%
Colowyo Coal Company			
1992 through 2017	79,429 (4)	79,429	0.70%
Cyprus Coal Company			
1988 through 1997	1,700,000	1,900,000	0.60%
Mountain Coal Company			
1993 through 2000	600,000 (5)	800,000	0.67%
Powderhorn Coal Company			
1995 through 1999	150,000	350,000	0.69%
Seneca Coals, Ltd (6)			
1992 through 2004	439,800	(7)	1.00%
Trapper Mining, Inc.			
1992 through 2014	189,108 (8)	189,108	(9)

(1) The contract term is completed upon delivery of 144,843,970 tons regardless of the year in which delivery is completed. From January 1, 1976 through December 31, 1996, 79,573,842 tons have been delivered.

(2) Coal requirements of Comanche and Pawnee.

(3) Coal requirements of Pawnee and Pawnee 2.

(4) The contract minimum quantity varies by year during the agreement from 79,429 tons in 1996 to 124,810 tons in 2017.

(5) The contract term is completed on December 31, 2000 or upon delivery of 3,200,000 tons. As of December 31, 1996, 2,181,740 tons have been delivered.

(6) The contract term is completed upon total delivery of 31,250,000 tons to Hayden from and after January 1, 1983. As of December 31, 1996, 20,604,164 tons have been delivered. Delivery is expected to be completed in the year 2004.

(7) Coal requirements of Hayden.

(8) The contract minimum quantity varies by year during the agreement from 189,108 tons in 1996 to 140,621 tons in 2014.

(9) Not specified in the contract.

Each coal contract contains adjustment clauses which permit periodic price increases or decreases. See Note 9. Commitments and Contingencies - Purchase Requirements in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA for information regarding the Company's financial commitments under these contracts as well as coal transportation contracts.

Natural Gas and Fuel Oil

The Company uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for the Company's power plants are procured under short-term contracts on a competitive basis to provide an adequate supply of fuel.

Natural Gas Operations

During the period 1992-1996, PSCo and Cheyenne have experienced growth in the number of residential and commercial customers ranging from 1.4% to 3.4% annually. Since 1992, residential and commercial gas volumes sold have averaged 131.9 million dekatherms ("MMDth") annually. The growth of residential and commercial sales has steadily improved due primarily to stronger economic conditions in Colorado and Wyoming. Growth of commercial customers has been impacted by large commercial customers selecting to purchase gas directly from suppliers. PSCo and Cheyenne transport gas through their transmission and distribution facilities for large commercial and industrial customers which purchase gas directly from suppliers. Fees for transportation services, which are paid by these customers, substantially offset the effect on net income of the revenue loss from decreased sales of gas to these customers. During 1996, transportation services generated revenues of $28.5 million compared to $23.8 million in 1995 and $23.5 million in 1994.

The Company recognizes that the divestiture of its existing gas business or certain non-utility ventures is a possibility under the new registered holding company structure proposed as part of the merger with SPS (see Note 3. Merger in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA). The Company is seeking approval from the SEC to maintain these businesses and currently does not anticipate that divestiture will be required. If divestiture is ultimately required, the SEC has historically allowed companies sufficient time to accomplish divestitures in a manner that protects shareholder value.

For a discussion of non-regulated gas marketing operations, see information in "e prime and subsidiaries".

Natural Gas Supply and Storage

PSCo and Cheyenne have attempted to maintain low cost, reliable natural gas supplies by optimizing a balance of long- and short-term gas purchase, firm transportation and gas storage contracts. During 1996, PSCo and Cheyenne purchased 142.2 MMDth from approximately 71 suppliers, including the following major suppliers: Interstate (39.9 MMDth); Western Gas Resources (12.2 MMDth); Barrett Resources (11.4 MMDth); Amoco Energy Trading Co. (11.3 MMDth); and PanEnergy Gas Services, Inc. (6.0 MMDth). In 1996, the average delivered cost per one thousand dekatherms ("MDth") for PSCo and Cheyenne was $2.58 compared to $2.22 per MDth in 1995 and $2.85 per MDth in 1994. Purchased gas costs are recovered from customers through the GCA (see "Regulation and Rates - State Regulation - Electric and Gas Adjustment Clauses").

Interstate was the largest gas supplier to PSCo and Cheyenne in 1996. During 1993, PSCo and Cheyenne entered into two non-regulated supply agreements, as allowed under FERC Order 636. Under the agreement with Interstate, which covered the period from October 1, 1993 through September 30, 1996, the annual quantities purchased declined from 46 MMDth in the first year to 34 MMDth in the second year and declined to 23 MMDth in the third year. Under the agreement with KN Gas Supply Services, Inc., which covered the period from September 1, 1993 through August 31, 1996, the annual quantities to be purchased were fixed at 4 MMDth. During 1996, PSCo and Cheyenne entered into new contracts with Interstate and others for firm transportation and gas storage services with terms of 5-7 years. Adequate supplies of natural gas are currently available for delivery within the Rocky Mountain region. PSCo and Cheyenne continually evaluate the natural gas market and procure supplies, as needed, to meet current and anticipated customer demand.

Regulation and Rates

The Company is subject to the jurisdiction of the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. Cheyenne is subject to the jurisdiction of the WPSC. The Company is subject to the jurisdiction of the DOE through the FERC with respect to its wholesale electric operations and accounting practices and policies. The Company is also subject to the jurisdiction of the NRC with respect to the decommissioning of Fort St. Vrain. Although the Company is a "holding company" under the PUHCA, it has filed an annual exemption statement pursuant to Rule 2 of the SEC under that Act and is, therefore, currently exempt from all of the provisions of such Act and the Rules thereunder, except Section 9(a)(2) thereof. Such

exemption is subject to termination under Rule 6 of PUHCA. On January 30, 1996, as part of the Merger of the Company with SPS, NCE filed its application with the SEC to be a registered public utility holding company, which would subject the Company and its subsidiaries to regulation under PUHCA (see "Recent Developments" in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS).

The Company holds a FERC certificate which allows it to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act, the Natural Gas Policy Act of 1978 and FERC Order Nos. 436 and 500 without the Company becoming subject to full FERC jurisdiction. WGI and TOP each hold a FERC certificate which allows them to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act. WGI and TOP are subject to FERC jurisdiction. e prime and TOG have authorization from FERC to act as power marketers.

Merger Rate Filings

See Note 3. Merger and Note 9. Commitments and Contingencies - Regulatory Matters - Merger Rate Filings in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

State Regulation

CPUC

The CPUC consists of three full-time members appointed by the Governor and approved by the Colorado Senate. Only two members may be from the same political party.

In 1996, the CPUC opened an inquiry docket related to electric utility restructuring. The Company submitted a response to a CPUC sponsored restructuring questionnaire which was followed by the CPUC issuing a summary of all responses. The CPUC is currently working with the Colorado General Assembly in its investigation and implementation of public policy.

Gas Rate Case

See Note 9. Commitments and Contingencies - Rate Case in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Electric and Gas Adjustment Clauses

At December 31, 1996, the Company has four adjustment clauses: the ICA (which replaced the ECA), GCA, DSMCA and QFCCA. These adjustment clauses allow certain costs to be passed through to retail customers. The Company and Cheyenne are required to file applications with their respective state regulatory commissions for approval of adjustment mechanisms in advance of the proposed effective date. The applications must be acted upon before becoming effective.

During 1994 and 1995, the CPUC conducted several proceedings to review issues related to the ECA. The CPUC opened a docket to review whether the ECA should be maintained in its present form, altered or eliminated, and on January 8, 1996, combined this docket with the Merger docket discussed in Note 9. Commitments and Contingencies - Regulatory Matters - Merger Rate Filings in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA. The CPUC decision on the Merger modified and replaced the ECA with the ICA. The ICA, which became effective October 1, 1996, allows for a 50%/50% sharing of certain fuel and energy cost increases and decreases among customers and shareholders.

The Company, through its GCA, is allowed to recover the difference between its actual costs of purchased gas and the amount of these costs recovered under its base rates. The GCA rate is revised annually on October 1 and otherwise as needed, to coincide with changes in purchased gas costs. Purchased gas costs and

revenues received to recover such gas costs are compared on a monthly basis and differences, including interest, are deferred.

The CPUC has had an on-going docket to review the status of the GCA and will determine whether it should be maintained in its present form, altered or eliminated. The CPUC conducted hearings regarding this matter on February 14, 1997. Additional hearings have been scheduled for March 7, 1997.

The QFCCA was implemented on December 1, 1993. Under the QFCCA, all purchased capacity costs from new QF projects, not otherwise reflected in base electric rates, are recoverable. The DSMCA is discussed below in "Incentive Regulation and Demand Side Management".

Incentive Regulation and Demand Side Management

The Company, in a collaborative process with public interest groups, consumers and industry, has developed DSM programs (programs designed to reduce peak electricity demand, shift on-peak demand to off-peak hours and provide for more efficient operation of the electric generation system), including incentive and cost recovery mechanisms. The CPUC approved the programs in 1993 along with a schedule to be implemented over a three-year period. Effective July 1, 1993, the Company implemented a DSMCA clause which permits it to recover deferred DSM costs over seven years while non-labor incremental expenses, carrying costs associated with deferred DSM costs and certain incentives associated with the approved DSM programs are recovered on an annual basis.

The CPUC subsequently opened a separate docket to investigate issues involving alternative annual revenue reconciliation mechanisms and incentive mechanisms related to the Company's DSM programs. The investigation was completed in 1995 and a final order was issued. The major provisions of the final order, effective December 27, 1995, included: 1) not to proceed with any of the proposed mechanisms; 2) to reduce the recovery period for certain costs of the Company's DSM programs from seven to five years for expenditures made on or after January 1, 1995; 3) not to establish DSM targets for 1997 and 1998; 4) not to adopt a penalty for failure to achieve DSM targets; and 5) to approve the Company's proposal to forego incentive payments for DSM programs.

Under a separate CPUC order issued in December 1992, the Company has implemented a Low-Income Energy Assistance Program. The costs of this energy conservation and weatherization program for low-income customers are recoverable through the DSMCA.

IRP - Electric

The Company filed a new IRP with the CPUC in October 1996. A final order is expected in 1997.

WPSC

In June 1993, Cheyenne filed gas and electric IRPs with the WPSC pursuant to a settlement agreement. The WPSC has not formally acted on these filings.

The WPSC has approved adjustment mechanisms which permit Cheyenne to recover purchased energy costs.

Federal Energy Regulatory Commission

See Note 9. Commitments and Contingencies - Regulatory Matters - Rate Cases in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA for information related to the Company's FERC rate case.

Information regarding FERC Order No. 888, Order No. 889 and the NOPR on Capacity Reservation Open Access Transmission Tariffs is discussed in Note 9. Commitments and Contingencies - Regulatory Matters - Federal Energy Regulatory Commission in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA .

Environmental Matters

Environmental regulations at the Federal, state and local levels, including the Clean Air Act Amendments (CAAA) of 1990 and other environmental matters, are expected to have a continuing impact on the Company's operations. See Note 9. Commitments and Contingencies - Environmental Issues in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA for a discussion of the impact on the Company of the CAAA of 1990, environmental site clean-up, and other environmental matters not discussed below. The Company continues to strive to achieve compliance with all environmental regulations currently applicable to its operations. However, it is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, generally, what effect future laws or regulations may have upon the Company's operations.

At December 31, 1996, the estimated 1997, 1998 and 1999 expenditures for environmental air and water emission control facilities were $29.6 million, $43.7 million and $23.2 million, respectively. As discussed below the Company's share of estimated cost to install emission control equipment at the Hayden station for the years 1997 through 1999 is approximately $70 million.

The Company continues to research and implement various SO2 and NOx emissions reduction projects, including two CCT3 projects. The CCT3 projects are part of a larger DOE Clean Coal Program, which co-funds developing technologies aimed at more efficient and environmentally acceptable methods of burning coal. Research and implementation continues on the two CCT3 projects, which involve Arapahoe Unit 4 and Cherokee Unit 3. Modification and testing at Cherokee Unit 3 and Arapahoe Unit 4 was conducted through 1996 and is expected to continue into 1997.

The Company is currently participating in the Northern Front Range Air Quality Study (NFRAQS), a follow-up study to the previous Metro Denver Brown Cloud Studies, which is designed to investigate the formation of secondary particulates in the Denver metropolitan area. The previous study, completed in 1993, was inconclusive and did not offer any policy recommendations. The NFRAQS began field sampling in early December 1996 and is expected to be completed by December 1997. Also, the EPA issued a draft particulate regulation in 1996, requesting public comments on the proposed regulation with issuance of the final regulation expected in June 1997. The Company is currently evaluating the impact of this new regulation on its operations.

The Mount Zirkel Wilderness Area ("MZWA") Reasonable Attribution Study, designed to ascertain the contribution of various emission sources to visibility impairment in the MZWA was completed in 1996. The Company is a participant in the Hayden and Craig generating stations, in the nearby Yampa Valley. The study results revealed that the Hayden and Craig Stations were minor contributors to visibility impairment in the MZWA. In May 1996, the joint owners of the Hayden station reached a settlement with a conservation organization, the Colorado Department of Public Health and Environment, and the EPA to resolve alleged air quality concerns in the Yampa Valley. The settlement, among certain other items, will result in the installation of additional emission control equipment at the Hayden station (see Note 9. Commitments and Contingencies - Environmental Issues in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Pursuant to the requirements of the Federal Clean Water Act, as amended, and the Colorado Water Quality Control Act and regulations issued thereunder, the Company receives National Pollution Discharge Elimination System permits to discharge effluents into various streams and waters of the State of Colorado for each of its generating stations. These permits, which have a five-year life, are issued by the CWQCD, but are subject to review by the EPA. The Company believes it is presently in compliance with such discharge permits.

Renewed wastewater discharge permits have been issued for: 1) Fort St. Vrain, effective April 1, 1993; 2) Cherokee, effective July 1, 1993; 3) Zuni, effective August 1, 1993; 4) Hayden, effective August 1, 1994; 5) Valmont, effective October 1, 1994; 6) Arapahoe, effective December 1, 1994; 7) Cameo, effective December 1, 1994 and 8) Comanche effective July 1, 1996. A renewal wastewater discharge permit for the Leyden Gas Storage facility is expected in the first quarter of 1997. All discharge permits that are not renewed by the

CWQCD prior to their expiration date automatically receive an administrative extension pending the issuance of a final permit.

The Company has completed the preparation of applications for Operating Permits as required by Title V of the 1990 CAAA. Permits were submitted to the state health department to meet 1996 submittal deadlines. The Company received its first Operating Permit in December 1996 for the Denver Steam Plant. The Company has applied for an early election of annual NOx emission limits for six units including Cherokee Units 3 and 4, Valmont Unit 5, Pawnee Unit 1, and Comanche Units 1 and 2. If the Company meets emission limits for these six units, as required by the early election, the Company would have until the year 2008, rather than the year 2000, to meet the lower emission limits established by Phase II of the CAAA.

Competition

Industry Outlook

Unprecedented change is occurring in the electric utility industry nationwide, furthering the development of a competitive environment. In general, the economics of the electric generation business have fundamentally changed with open transmission access and the increased availability of electric supply alternatives. Such alternatives will ultimately serve to lower customer prices, particularly in areas where only higher cost energy is currently provided. Customer demands for lower prices and supplier choices, the availability of alternative supplies (IPPFs, QFs, EWGs and power marketers), and open access to the utility transmission grid have resulted in a commodity market for bulk electric supply. The EPAct directly addressed this issue by giving the FERC the authority to require utilities to provide non-discriminatory open access to the transmission grid for purposes of providing wholesale customers with direct access. In response to such authority, in early 1996, the FERC issued new rules on open access transmission services. Furthermore, an increasing number of states with above average energy prices are pursuing full competition in the electric industry.

The presence of competition and the associated pressure on prices may ultimately lead to the unbundling of products and services similar to what has evolved in the natural gas industry. Today's market view of the future envisions an unbundled electric utility industry consisting of at least four major business segments: energy supply, transmission, distribution and energy services - each having a different driving force.

The SEC has also responded to increasing competition in the utility industry and changes in state and federal utility regulation. In June 1995, the SEC issued its report which focused on both legislative and administrative options for the reform of public utility holding company regulation. The report presented three possible recommendations for legislative reform of PUHCA: 1) conditional repeal of PUHCA, 2) unconditional repeal of PUHCA, and 3) PUHCA remains unmodified, but grants the SEC broader exemptive authority under PUHCA. Any changes in regulation will be determined by Congress.

Further discussion can be found in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

State Regulatory Environment

Colorado law permits the CPUC to authorize rates negotiated with individual electric and gas customers which have threatened to discontinue using the services of the Company, so long as the CPUC finds that such authorization: 1) in the case of electric rates, will not adversely affect the Company's remaining customers and 2) in the case of gas rates, will not affect the Company's remaining customers as adversely as would the alternative. In response to the increasingly competitive operating environment for utilities, the regulatory climate is also changing. The CPUC recently issued a report on a comprehensive survey on electric industry restructuring. The Company continues to participate in regulatory proceedings which could change or impact current regulation. The Company believes it will continue to be subject to rate regulation that will allow for the recovery of all of its deferred costs (see Note 1. Summary of Significant Accounting Policies - Business and Regulation - Regulatory

Assets and Liabilities and Note 9. Commitments and Contingencies - Regulatory Matters in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Electric

The wholesale electric business faces increasing competition in the supply of bulk power due to provisions of the EPAct and Federal and state initiatives with respect to providing open access to utility transmission systems. Under the new FERC rules issued in early 1996, utilities are required to provide wholesale open-access transmission services consistent with what is provided for in their own operations. The Company and Cheyenne are operating with the tariffs approved by the FERC under these new rules. To date, these provisions have not had a material impact on the Company's operations. For 1996, the Company's wholesale revenues totaled approximately 8% of total electric revenues. A substantial portion of these revenues related to firm sales contracts, which are expected to continue at current levels for a minimum of 10 years.

Today, the retail electric business faces increasing competition from industrial and large commercial customers who have the ability to own or operate facilities to generate their own electric energy requirements. In addition, customers may have the option of substituting fuels, such as natural gas for heating, cooling and manufacturing purposes rather than electric energy, or of relocating their facilities to a lower cost environment. While the Company faces these challenges, it believes its rates are competitive with currently available alternatives. The Company is taking actions to lower operating costs and is working with its customers to analyze the feasibility of various options, including energy efficiency, load management and co-generation in order to better position the Company to more effectively operate in a competitive environment.

Natural Gas

Historically, gas utilities have competed with suppliers of electricity and fuel oil, as well as to a lesser extent, propane, for sales of gas to customers for heating and/or cooling purposes. In the 1980s, industrial and large commercial customers began to "by-pass" the local gas utility through the construction of interconnections directly with, and the purchase of gas directly from, interstate pipelines, thereby avoiding the additional charges added by the local gas utility. In addition, industrial and commercial customers sought to purchase less expensive supplies of natural gas directly from producers, marketers and brokers. The Company has been actively involved for several years in providing transportation services for those industrial and large commercial customers which chose to purchase gas directly from suppliers. In addition, the Company has provided flexible transportation rates for several years. The per-unit fee charged for transportation services, while significantly less than the per-unit fee charged for the sale of gas to a similar customer, provides an operating margin approximately equivalent to the margin earned on gas sold. Therefore, increases in such activities will not have as great an impact on gas revenues as increases in deliveries from the sale of gas, but will have a positive impact on operating margin. In 1995, the Company organized e prime to engage in the non-regulated marketing of natural gas in order to expand its marketshare.

Franchises

The Company and its subsidiaries held nonexclusive franchises to provide electric or gas service or both services in 120 incorporated cities and towns at December 31, 1996. These franchises consist of 69 combined gas and electric service franchises, 29 electric service franchises and 22 gas service franchises. In 1997, the Company expects to renegotiate four of the franchise agreements which will be expiring. The Company's franchise with the City of Denver will expire in 2006. The Company and its subsidiaries supply electric or gas service or both services in about 114 unincorporated communities in which franchises are not required.

Employees and Union Contracts

The number of employees of the Company and its subsidiaries decreased from 4,776 at December 31, 1995 to 4,675 at December 31, 1996. Approximately, 2,090 employees, or 45% of the Company's total

workforce, are represented by the International Brotherhood of Electrical Workers, Local 111. The number of employees covered by collective bargaining agreements at December 31, 1996 approximated 2,284.

Research and Development

The Company and its utility subsidiaries spent approximately $3.8 million in 1996, $3.6 million in 1995 and $3.8 million in 1994 on research and development. The major portion of those expenditures went to utility associations which engage in research projects to benefit the electric and gas industries as a whole. The balance of the expenditures went for smaller internal and external projects dealing with such areas as pollution control and alternative fuels research.

Consolidated Electric Operating Statistics

	Year Ended December 31,				
	1996	1995	1994	1993	1992
Energy Generated, Received, & Sold (Thousands of Kwh):					
Net Generated:					
Steam, Fossil	17,099,890	16,053,928	15,949,980	15,470,247	14,972,688
Combustion Turbine	121,079	5,251	41,705	39,228	47,194
Pumped Storage	178,205	68,400	126,721	118,593	79,609
Hydro	197,660	208,104	176,264	198,272	175,010
Total Net Generation	17,596,834	16,335,683	16,294,670	15,826,340	15,274,501
Energy Used for Pumping	276,983	109,632	201,744	185,850	126,266
Total Net System Input	17,319,851	16,226,051	16,092,926	15,640,490	15,148,235
Purchased Power and Net Interchange	10,349,298	9,794,968	9,653,067	9,631,982	8,663,339
Total System Input	27,669,149	26,021,019	25,745,993	25,272,472	23,811,574
Used by Company	57,603	64,885	66,348	60,396	64,125
Other (1)	1,352,843	1,526,358	1,670,591	2,001,832	1,932,333
Total Energy Sold	26,258,703	24,429,776	24,009,054	23,210,244	21,815,116
Electric Sales (Thousands of Kwh) (2):					
Residential	6,606,601	6,281,911	6,119,914	5,969,529	5,747,048
Commercial	9,880,502	9,284,577	8,931,962	10,797,272	10,350,155
Industrial	5,791,608	5,747,534	5,726,837	3,289,501	3,375,638
Public Authorities	200,070	188,363	187,939	186,397	187,500
Wholesale - Regulated	3,361,217	2,927,391	3,042,402	2,967,545	2,154,775
Wholesale Energy Services - Non-Regulated	418,705	-	-	-	-
Total Energy Sold	26,258,703	24,429,776	24,009,054	23,210,244	21,815,116
Number of Customers at End of Period(2):					
Residential	959,249	936,759	913,582	898,752	894,217
Commercial	126,426	123,277	120,886	120,317	120,198
Industrial	380	378	384	157	194
Public Authorities	79,725	79,154	77,842	76,476	647
Wholesale - Regulated	26	17	18	20	34
Wholesale Energy Services - Non-Regulated	6	-	-	-	-
Total Customers	1,165,812	1,139,585	1,112,712	1,095,722	1,015,290
Electric Revenues (Thousands of Dollars)(2):					
Residential	$ 507,233	$ 477,740	$ 453,614	$ 433,521	$ 413,655
Commercial	571,536	552,905	519,340	602,187	572,780
Industrial	249,774	257,189	252,552	142,146	148,951
Public Authorities	25,798	23,029	21,950	20,828	20,221
Wholesale - Regulated	120,478	114,514	120,238	116,937	80,290
Wholesale Energy Services - Non-Regulated	7,806	-	-	-	-
Other Electric Revenues	6,365	23,719	32,142	21,434	24,872
Total Electric Revenues	$ 1,488,990	$ 1,449,096	$ 1,399,836	$ 1,337,053	$ 1,260,769
Average Annual Kwh Sales per Residential Customer	6,965	6,794	6,770	6,717	6,533
Average Annual Revenue per Residential Customer	$534.79	$516.70	$501.82	$487.81	$470.26
Average Residential Revenue per Kwh	7.68¢	7.61¢	7.41¢	7.26¢	7.20¢
Average Commercial Revenue per Kwh	5.78¢	5.96¢	5.81¢	5.58¢	5.53¢
Average Industrial Revenue per Kwh	4.31¢	4.47¢	4.41¢	4.32¢	4.41¢
Average Wholesale - Regulated Revenue per Kwh	3.58¢	3.91¢	3.95¢	3.94¢	3.73¢

(1) Primarily includes net distribution and transmission line losses.

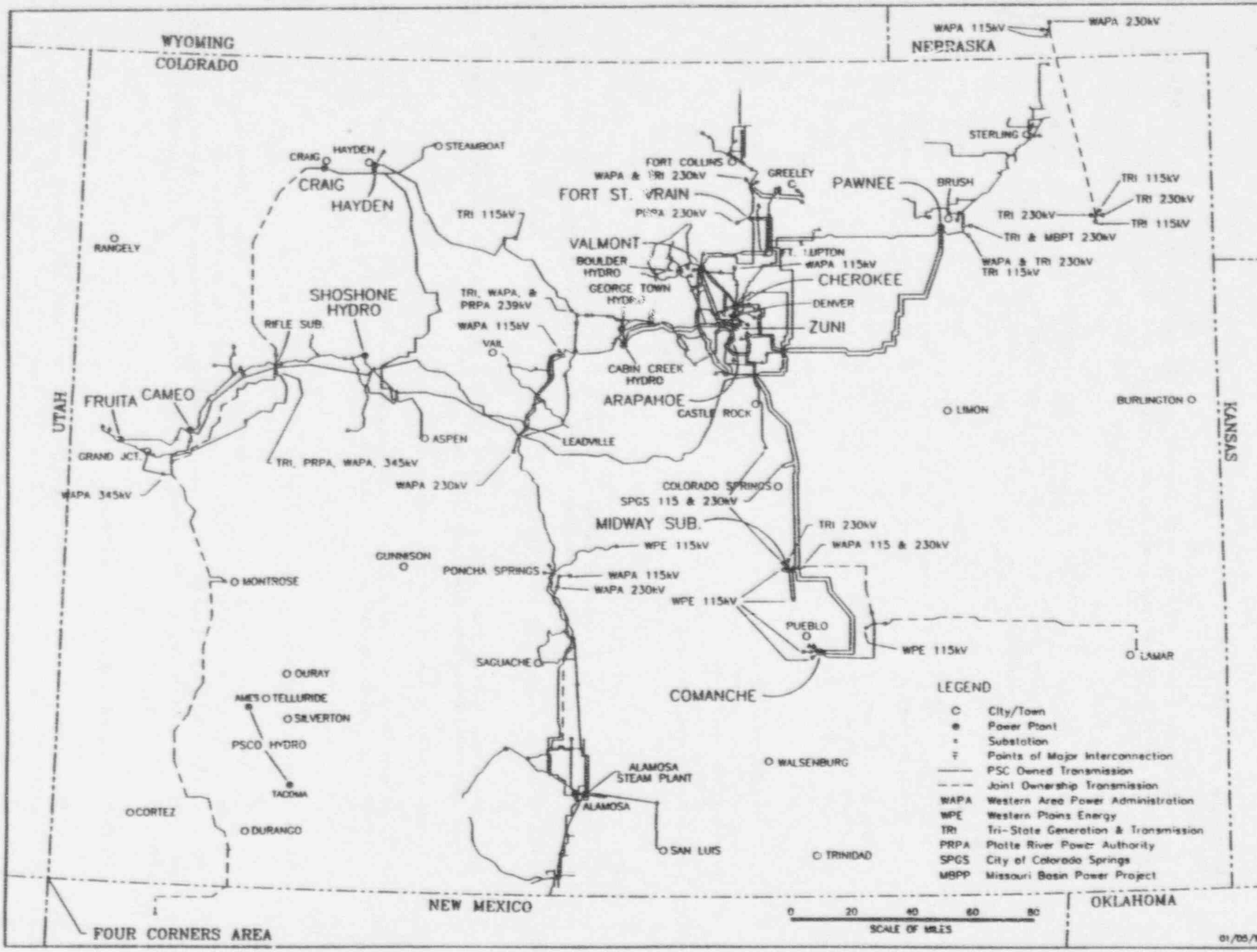
(2) Comparison of energy sales, customers and electric revenues between periods is impacted by: 1) a change in criteria for counting customers resulting from the implementation of a new customer information system during 1993, and 2) effective January 1, 1994, a reclassification to include large commercial customers (>1,000 Kw demand) within the industrial category, to be consistent with recommended utility industry guidelines.

Consolidated Gas Operating Statistics

	Year Ended December 31,				
	1996	1995	1994	1993	1992
Natural Gas Purchased and Sold (Thousands of Dth):					
Purchased from Interstate	39,924	38,687	45,177	55,078	59,328
Purchased from Others	107,374	101,259	88,174	88,482	79,011
Purchased for Non-regulated Gas Marketing (1)	22,807	237	-	-	-
Total Purchased	170,105	140,183	133,351	143,560	138,339
Company Use	520	1,330	2,386	2,349	2,603
Other (2)	10,000	5,657	3,824	(1,803)	6,052
Total Gas Sold	159,585	133,196	127,141	143,014	129,684
Gas Deliveries (Thousands of Dth):					
Residential	86,102	82,188	77,955	83,991	74,951
Commercial	50,100	50,463	48,689	54,125	50,705
Wholesale	1,555	308	497	4,898	4,028
Non-regulated Gas Marketing (1)	21,828	237	-	-	-
Total Gas Sold	159,585	133,196	127,141	143,014	129,684
Transportation	90,304	75,704	66,230	61,421	51,706
Gathering and Processing (3)	1,141	1,391	25,316	35,877	28,292
Total Deliveries	251,030	210,291	218,687	240,312	209,682
Number of Customers at End of Period:					
Residential	902,078	872,777	845,464	820,521	808,722
Commercial	90,761	89,034	87,103	86,227	86,192
Wholesale	-	-	8	8	8
Non-regulated Gas Marketing (1)	1,255	2	-	-	-
Total	994,094	961,813	932,575	906,756	894,922
Transportation and Other	1,794	952	786	619	416
Total Customers	995,888	962,765	933,361	907,375	895,338
Gas Revenues (Thousands of Dollars):					
Residential	362,481	$ 383,719	$ 375,406	$ 366,445	$ 329,406
Commercial	173,308	200,314	203,311	204,820	191,366
Wholesale	3,020	4,961	7,319	13,966	10,099
Non-regulated Gas Marketing (1)	64,389	399	-	-	-
Transportation	28,549	23,769	23,495	23,176	20,638
Gathering and Processing	364	443	8,335	10,575	8,023
Other Gas Revenues	8,386	10,980	7,056	9,342	9,354
Total Gas Revenues	$ 640,497	$ 624,585	$ 624,922	$ 628,324	$ 568,886
Average Annual Dth Sales per Residential Customer	97.14	95.65	93.67	103.21	93.73
Average Annual Revenue per Residential Customer	$408.93	$446.58	$451.09	$450.29	$411.94
Average Revenue per Dekatherm:					
Residential	$4.210	$4.669	$4.816	$4.363	$4.395
Commercial	$3.459	$3.970	$4.176	$3.784	$3.774
Transportation	$0.316	$0.314	$0.355	$0.377	$0.399

(1) Includes purchases and sales by e prime and TOG.
(2) Primarily includes distribution and transmission line losses and net changes to gas in storage.
(3) In August 1994, the Company sold WGG, which resulted in the decline in gathering and processing deliveries.

PUBLIC SERVICE COMPANY OF COLORADO
ELECTRIC TRANSMISSION INTERCONNECTED SYSTEM



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Item 2. *Properties*

Electric Generation Property

The electric generating stations of the Company and its subsidiaries expected to be available at the time of the anticipated 1997 net firm system peak demand during the summer season are as follows:

Name of Station and Location	Installed Gross Capacity (Mw)		Net Dependable Capacity (Mw) at Time of Anticipated 1997 Net Firm System Peak Demand*		Major Fuel Source
Steam:					
Arapahoe-Denver	262.00		246.00		Coal
Cameo-near Grand Junction	77.00		72.70		Coal
Cherokee-Denver	784.00		723.00		Coal
Comanche-near Pueblo	725.00		660.00		Coal
Craig-near Craig	86.90	(a)	83.20		Coal
Hayden-near Hayden	259.00	(b)	237.00		Coal
Pawnee-near Brush	530.00		495.00		Coal
Valmont-near Boulder (Unit 5)	188.00		178.00		Coal
Zuni-Denver	115.00		107.00		Gas/Oil
Total	3,026.90		2,801.90		
Fort St. Vrain Combustion Turbine - near Platteville	141.45		126.75		Gas
Combustion turbines (6 units-various locations)	209.00		171.00		Gas
Hydro (14 units-various locations) (c)	53.35		36.55	(d)	Hydro
Cabin Creek Pumped Storage-near Georgetown	324.00	(e)	162.00		Hydro
Cherokee Diesel generators (2 units)	5.50		5.50		Oil
Total	3,760.20		3,303.70		

* A measure of the unit capability planned to be available at the time of the system peak load net of seasonal reductions in unit capability due to weather, stream flow, fuel availability and station housepower, including requirements for air and water quality control equipment.

(a) The gross maximum capability of Craig Units No. 1 and No. 2 is 894 Mw, of which the Company has a 9.72% undivided ownership interest.

(b) The gross maximum capability of Hayden Units No. 1 and No. 2 is 202.01 Mw and 285.96 Mw, respectively, of which the Company has a 75.5% and 37.4% undivided ownership interest, respectively.

(c) Includes one station (two units) not owned by the Company but operated under contract.

(d) Seasonal Hydro Plant net dependable capabilities are based upon average water conditions and limitations for each particular season. The individual plant seasonal capabilities are sometimes limited by less than design water flow.

(e) Capability at maximum load.

Nuclear Generation Property

Fort St. Vrain, near Platteville, the Company's only previous nuclear generating station, ceased operations on August 29, 1989 and on March 22, 1996 the physical decommissioning of the station was completed. The initial phase of the repowered gas fired combined cycle steam electric generating station began commercial operations on May 1, 1996 (see Note 2. Fort St. Vrain in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Electric Transmission and Distribution Property

On December 31, 1996, the Company's transmission system consisted of approximately 112 circuit miles of 345 Kv overhead lines; 1,916 circuit miles of 230 Kv overhead lines; 15 circuit miles of 230 Kv underground

lines; 65 circuit miles of 138 Kv overhead lines; 999 circuit miles of 115 Kv overhead lines; 20 circuit miles of 115 Kv underground lines; 344 circuit miles of 69 Kv overhead lines; 143 circuit miles of 44 Kv overhead lines; and 1 circuit mile of 44 Kv underground lines. The Company jointly owns with another utility approximately 342 circuit miles of 345 Kv overhead lines and 360 miles of 230 Kv overhead lines, of which the Company's share is 112 miles and 147 miles, respectively, which shares are included in the amounts listed above.

The Company's transmission facilities are located wholly within Colorado. The map on page 16 illustrates the Company's transmission interconnected system. The system is interconnected with the systems of the following utilities with which the Company has major firm purchase power contracts; capacity and energy are provided primarily by generating sources in the locations indicated:

Utility	Location
Basin Electric Power Cooperative	Southeast Wyoming
PacifiCorp	West & Northwest U.S. Northwest Colorado
Platte River Power Authority	Northcentral Colorado
Tri-State.	Southeast Wyoming and Northwest Colorado

The Company has wheeling agreements with the above, and with other utilities and public power agencies, which are utilized to provide capacity and energy to the Company's system from time to time.

The Company is a member of the WSCC, an interstate network of transmission facilities which are owned by public entities and investor-owned utilities. WSCC is the regional reliability coordinating organization for member electric power systems in the western United States.

At December 31, 1996, the distribution systems consisted primarily of approximately 12,939 miles of overhead line, 1,068 miles of which are located on poles owned by other utilities under joint use agreements. The Company also owned approximately 7,891 cable miles of underground distribution system (excluding street lighting) located principally in the Denver metropolitan area. The Company owned 219 substations (four of which are jointly owned) having an aggregate transformer capacity of 18,705,000 Kva, of which 4,145,827 Kva is step-up transformer capacity at generating stations.

Gas Property

The gas property of the Company at December 31, 1996 consisted chiefly of approximately 15,304 miles of distribution mains ranging in size from 0.50 to 30 inches and related equipment. The Denver distribution system consisted of 8,691 miles of mains. Pressures in the low pressure system are varied to meet load requirements and individual house regulators are installed on each customer's premises to provide uniform flow of gas to appliances. The Company also owns and operates four gas storage facilities.

Other Property

The Company's steam heating property at December 31, 1996 consisted of 10.5 miles of transmission, distribution and service lines in the central business district of Denver, including a steam transmission line connecting the steam heating system with Zuni. Steam is supplied from boilers installed at the Company's Denver Steam Plant which has a capability of 295,000 pounds of steam per hour under sustained load and an additional 300,000 pounds of steam per hour is available from Zuni on a peak demand basis. The Company also owns service and office facilities in Denver and other communities strategically located throughout its service territory.

Property of Subsidiaries

The book value of the properties of the consolidated subsidiaries of the Company aggregates approximately 3% of the total book value of the properties of the Company and such subsidiaries combined. Such properties consist largely of electric and gas properties similar in character to the properties of the Company. Unregulated subsidiary property is approximately 1% of the total book value of the properties of the Company and consolidated subsidiaries combined. 1480 Welton, Inc. owns two buildings that are used by the Company.

Character of Ownership

The steam electric generating stations, the majority of major electric substations and the major gas regulator stations owned by the Company and its subsidiaries are on land owned in fee. Approximately half of the compressor stations and a limited number of town border and meter stations are also on land owned in fee. The remaining major electric substations and compressor stations and the majority of gas regulator stations and town border and meter stations are wholly or partially on land leased from others or on or along public highways or on streets or public places within incorporated towns and cities. The Company's Cabin Creek Pumped Storage Hydroelectric Generating Station, its Shoshone Hydroelectric Generating Station and a portion of the related intake tunnel are located on public lands of the United States. As to substantially all property on or across public lands of the United States, the Company or its subsidiaries hold licenses or permits issued by appropriate Federal agencies or departments. The Leyden gas storage facility is located largely on leased property under leases expiring December 31, 2040. The Company and its utility subsidiaries have the power of eminent domain pursuant to Colorado law to acquire property for their electric and gas facilities. The electric and gas transmission and distribution facilities are for the most part located over or under streets, public highways or other public places and on public lands under franchises or other rights, and on land owned by the Company or others pursuant to easements obtained from the record holders of title. The water rights of the Company and its subsidiaries are owned subject to divestment to the extent of any abandonment thereof.

Substantially all of the utility plant and other physical property owned by the Company and its utility subsidiaries is subject to the liens of the respective indentures securing the mortgage bonds of the Company and its utility subsidiaries.

Item 3. ***Legal Proceedings***

See Note 9. Commitments and Contingencies in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Item 4. ***Submission of Matters to a Vote of Security Holders***

Does not apply.

PART II

Item 5. ***Market for Registrant's Common Equity and Related Stockholder Matters***

The Company's common stock is listed on the New York, Chicago and Pacific Stock Exchanges. The following table sets forth for the periods indicated the dividends declared per share of common stock and the high and low sale prices of the common stock on the consolidated tape as reported by *The Wall Street Journal*.

Year and Quarter	Dividends Declared	Price Range High	Price Range Low
1996			
First Quarter	$ .525	$36 1/2	$33 3/4
Second Quarter	.525	36 3/4	32 3/8
Third Quarter	.525	36 7/8	34 3/4
Fourth Quarter	.525	39 1/2	35 1/4
	$2.10		
1995			
First Quarter	$ .51	$31 1/2	$ 29
Second Quarter	.51	32 7/8	29 1/4
Third Quarter	.51	34 1/2	30 5/8
Fourth Quarter	.51	35 7/8	33 3/8
	$2.04		

At December 31, 1996, the book value of the common stock was $22.19 per share. At February 21, 1997, there were 57,532 holders of record of the Company's common stock.

The dividend level is dependent upon the Company's results of operations, financial position and other factors and is evaluated quarterly by the Board of Directors. See Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

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. On August 22, 1995, in connection with the proposed merger (see Note 3. Merger in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA), the Company's Rights Agreement was amended to provide that NCE will not be deemed an "Acquiring Person" as a result of the execution, delivery, and performance of the Merger Agreement.

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 at least 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. For a description of the rights and their terms see the Company's Rights Agreement, as amended, which is an exhibit to this Form 10-K.

Item 6. *Selected Financial Data*

The following selected consolidated financial data of the Company and its subsidiaries for each of the five years in the period ended December 31, 1996 should be read in conjunction with the consolidated financial statements and the management's discussion and analysis of financial condition and results of operations appearing elsewhere herein.

	Year Ended December 31,				
	1996	1995	1994	1993	1992
	(In Thousands-except per share data & ratios)				
Operating revenues:					
Electric	$1,488,990	$1,449,096	$1,399,836	$1,337,053	$1,260,769
Gas	640,497	624,585	624,922	628,324	568,886
Other	41,899	36,920	32,626	33,308	32,618
Total	2,171,386	2,110,601	2,057,384	1,998,685	1,862,273
Total operating expenses	1,8[illegible],902	1,784,784	1,786,592	1,717,752	1,612,646
Operating income	3[illegible]8,484	325,817	270,792	280,933	249,627
Total interest charges	149,880	143,906	132,134	130,337	121,116
Net income	190,346	178,856	170,269	157,360	136,623
Dividend requirements on preferred stock	11,848	11,963	12,014	12,031	12,077
Earnings available for common stock	178,498	166,893	158,255	145,329	124,546
Per share data applicable to common stock (a):					
Earnings	$2.78	$2.65	$2.57	$2.43	$2.16
Dividends declared	$2.10	$2.04	$2.00	$2.00	$2.00
Shares of common stock outstanding:					
Weighted average	64,187	62,932	61,547	59,695	57,558
Year-end	64,819	63,358	62,155	60,457	58,477
Rate of return earned on average common equity (net to common)	12.8%	12.8%	12.9%	12.7%	11.7%
Ratio of earnings to fixed charges (b)	2.75	2.78	2.53	2.54	2.43
Total assets	$4,572,648	$4,351,789	$4,207,832	$4,057,600	$3,759,583
Total net plant	3,598,895	3,480,712	3,291,402	3,193,136	3,077,509
Total construction expenditures	321,162	285,516	317,138	293,515	261,666
AFDC	4,101	7,095	7,158	12,667	11,302
Cash generated internally as a percent of construction expenditures (c)	59.5%	87.4%	35.4%	52.2%	57.5%
Total common equity	$1,438,288	$1,343,645	$1,267,482	$1,184,183	$1,101,047
Preferred stock:					
Not subject to mandatory redemption	140,008	140,008	140,008	140,008	140,008
Subject to mandatory redemption at par (including amounts due within one year)	42,469	43,865	45,241	45,454	45,654
Long-term debt (including amounts due within one year)	1,414,558	1,278,389	1,180,580	1,193,668	1,199,779
Notes payable & commercial paper	244,725	288,050	324,800	276,875	2[illegible],626

(a) Earnings per share are based on the weighted average number of shares of common stock outstanding.

(b) See Exhibit 12(a) herein.

(c) Calculated as cash provided by operations net of cash used for dividends, divided by construction expenditures net of AFDC equity-component.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

Industry Outlook

Fundamental changes continue to occur throughout the electric utility industry as it moves toward deregulation with customer choice and increased competition. Regulatory actions at both the federal and state level have opened up the wholesale, and to a lessor extent retail, markets to more competition. The FERC issued new rules in early 1996 requiring utilities to provide wholesale open-access transmission services and allowing for recc ery of stranded investment costs. A few states with above-average electric energy prices are aggressively pursuing full competition in the electric industry. Some states currently have pilot plans in place to allow retail customers to select their energy supplier. Federal legislation related to deregulation of the electric utility industry was introduced in 1996 and broad support for restructuring legislation is developing. In addition, the reform or repeal of PUHCA, the law which regulates the ownership and operation of public utility holding companies, is expected to be given serious consideration in 1997 by Congress. Utilities are responding to increased competition. Mergers, acquisitions and corporate restructurings have continued to occur nationally and globally as companies strive to position themselves for the future, achieving economies of scale and increases in productivity and efficiency.

Electric prices in Colorado are relatively low in comparison to other parts of the country, lessening the need for immediate change in the state's electric industry. In 1996, the CPUC performed a comprehensive survey on electric industry restructuring. The report issued by the CPUC is not conclusive on what the next steps should be. Clearly, the issues are complex and controversial with significant consequences to the Company's securities holders. The Company supports the need for change and believes that Colorado must take the time to study and learn from the restructuring models developed in other states to determine which aspects of those programs may be appropriate, and to identify other specific regional issues that need to be addressed. The Company's response to the survey included a proposal that the CPUC undertake a comprehensive study of these complex issues, which would provide the necessary foundation of information for consideration by the state legislature.

Corporate Overview

Significant progress on the Merger of the Company with SPS was achieved in 1996 and early 1997. Shareholder approvals were received in January 1996 and required authorizations were obtained from all state utility regulators. Final approvals and filings are in progress with completion of the merger anticipated in the spring of 1997. The Merger will permit the Company to derive benefits from the more efficient and economic utilization of combined facilities and personnel. With a larger and more geographically diverse combined service territory, the business risks related to changes in economic, competitive or climatic conditions will be reduced. In addition, purchasing savings, increased economical use of generation capacity and reduced administrative costs are anticipated. Merger transition plans have been developed to begin realizing synergy savings upon consummation of the Merger, although the savings expected for 1997 will be reduced somewhat by various Merger related costs, including those related to planned workforce reductions.

Operating priorities in 1996 continued to focus on reducing costs and developing new business opportunities. Positive earnings reflected the continued cost containment efforts initiated in 1994. The performance based regulatory plan approved by the CPUC resulted in a sharing arrangement between customers and shareholders of electric department earnings in excess of 11% for the years 1997-2001, a 50%/50% sharing of certain fuel and energy cost increases or decreases and a QSP which provides for penalties if certain performance measures relating to electric reliability, customer complaints and telephone response to inquiries are not met. The Company anticipates that a reward structure for performance above certain standards will be implemented in the near term.

In line with the Company's strategic focus on expanding market share and value, e prime received authorization from the FERC to act as a power marketer and is now marketing wholesale electricity. In September 1996, e prime acquired TOG, a gas marketing company which serves 1,400 industrial and commercial customers in the eastern U.S. In line with customer retention, the Company and one of its largest wholesale customers entered into a new purchase power agreement in which the Company provides power through the year

2001. This wholesale customer had previously notified the Company of its intent to reduce firm and peaking power purchases beginning in 1998. The Company continues to look for opportunities to expand its customer base as both a natural gas and electric energy provider and to advance its strategy to focus on customer needs, while building a national presence in the marketplace.

The regulatory environment within Colorado is a primary focus for the Company and the successful merger with SPS will likely have long-term effects on the Company's future financial performance. The Company strongly believes that all potentially stranded costs resulting from changes in laws or regulation should be recoverable. Additionally, the Company believes that it will continue to be subject to rate regulation that will allow for the recovery of all of its deferred costs. To the extent the Company concludes in the future that such recovery is no longer probable, the Company may be required to recognize as expense, at a minimum, all deferred costs currently recognized as regulatory assets on the consolidated balance sheet. (See Note 1. Summary of Significant Accounting Policies in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Recent Developments

On February 24, 1997, the Company and AEP jointly announced that they have reached agreement with the board of directors of Yorkshire Electricity, a UK regional electricity company, on the terms of a recommended cash tender offer for all of the outstanding and to be issued ordinary shares of Yorkshire Electricity. The Company and AEP, through a joint venture named Yorkshire Holdings, are offering the equivalent of US $15.02 (9.27 pounds) per ordinary share, for a total purchase price of approximately US $2.4 billion (1.5 billion pounds). The boards of directors of the Company and AEP have approved the transaction. The board of directors of Yorkshire Electricity has agreed to recommend the offer to Yorkshire Electricity's shareholders. The offer will be made through Yorkshire Holdings, a wholly-owned subsidiary of Yorkshire Power, a newly formed UK corporation owned equally by the Company and AEP. The Company will make its investment through New Century International, Inc., a wholly-owned subsidiary of the Company. If the Proposed Acquisition is completed, the Company would have an indirect 50% ownership interest in Yorkshire Electricity, which would be accounted for using the equity method of accounting. Consummation of the Proposed Acquisition is subject to customary conditions in the UK, including regulatory clearance and acceptance of the offer by holders of at least 90% of the outstanding shares of Yorkshire Electricity. Yorkshire Holdings may waive the latter condition when it has received acceptances of its offer and has otherwise acquired shares which in total represent more than 50% of the outstanding shares of Yorkshire Electricity. The Company cannot predict at this time whether or not these conditions will be met or waived.

The Proposed Acquisition will be financed by Yorkshire Power through a combination of approximately 25% equity and 75% debt, including the assumption of the existing debt of Yorkshire Electricity. The funds for the Proposed Acquisition will be obtained from the Company's and AEP's investment in Yorkshire Power of approximately US $360 million (220 million pounds) each, with the remainder to be obtained by Yorkshire Power through the issuance of non-recourse debt. Yorkshire Power will, in turn, fund Yorkshire Holdings for the purpose of the Proposed Acquisition. The Company intends initially to use debt to fund its entire equity investment in Yorkshire Power, including the issuance of US $250 million of its secured medium-term notes with varying maturities and drawings of US $110 million on its short-term lines of credit. It is currently anticipated that the Company's entire equity investment in Yorkshire Power will be refinanced through the issuance of common equity at the NCE level within six to eighteen months from the date of consummation of the Proposed Acquisition.

According to Yorkshire Electricity's 1996 Annual Report and Accounts, Yorkshire Electricity's principal activities are the distribution of electricity to 2.1 million industrial, commercial, agricultural and domestic customers in its authorized area, which covers 4,180 square miles of northeast England. Yorkshire Electricity is also active in electricity supply and generation and the supply of natural gas, including the ownership of gas assets. Other activities include the development of telecommunications services and the construction and operation of windfarms. For the fiscal year ended March 31, 1996, Yorkshire Electricity reported a consolidated profit on ordinary activities before taxation and exceptional items of US $310.8 million (199.2 million pounds) on

revenues of US $2.2 billion (1.4 billion pounds), had reported total assets at that date of US $2.2 billion (1.4 billion pounds), and reported net assets at that date of US $818.9 million (521.1 million pounds).

The SEC, in an order issued on February 19, 1997 under section 3(b) of PUHCA, exempted Yorkshire Electricity from all provisions of PUHCA that would be applicable to it as a subsidiary of the Company. In connection with its application for such order, the Company also requested and obtained a no-action letter from the Division of Investment Management of the Office of Public Utility Regulation of the SEC stating that, as long as the Merger is completed by September 30, 1997, it will not recommend any enforcement action with respect to the possible effect of the Proposed Acquisition on the Company's existing section 3(a)(2) exemption under PUHCA. In seeking the section 3(b) exemption for Yorkshire Electricity, the Company informed the SEC that its investment in Yorkshire Electricity would be less than 50% of the Company's and SPS's combined retained earnings as of September 30, 1996, consistent with the requirements of Rule 53 under PUHCA. The Company also informed the SEC in its application for a section 3(b) exemption that upon completion of the Merger, NCE would hold the proposed investment in Yorkshire Power through a separate subsidiary and not through the Company. At that time, Yorkshire Electricity would be qualified as a foreign utility company under section 33 of PUHCA.

See Note 4. Acquisition and Divestiture of Investments - Proposed Acquisition of Yorkshire Electricity in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Earnings

Earnings per share were $2.78, $2.65 and $2.57 during 1996, 1995 and 1994, respectively. The improved earnings in both 1996 and 1995 are primarily attributable to increased electric and gas margins resulting from higher sales and lower operating and maintenance expenses resulting from the Company's cost containment efforts. In addition, earnings in 1996 were favorably impacted by the February 9, 1996 settlement agreement with the DOE resolving all spent nuclear fuel storage and disposal issues at Fort St. Vrain (See Note 2. Fort St. Vrain in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Electric Operations

The following table details the annual change in electric operating revenues and energy costs as compared to the preceding year:

	Increase (Decrease) From Prior Years	
	1996	1995
	(Thousands of Dollars)	
Electric operating revenues:		
Retail	$ 43,478	$ 63,407
Wholesale	13,770	(5,724)
Other (including unbilled revenues)	(17,354)	(8,423)
Total revenues	39,894	49,260
Fuel used in generation	13,447	(16,123)
Purchased power	8,470	44,871
Net increase in electric margin	$ 17,977	$ 20,512

The following table summarizes electric sales by major customer classes:

	Millions of Kwh Sales 1996	Millions of Kwh Sales 1995	% Change * from prior years 1996	% Change * from prior years 1995
Residential	6,607	6,282	5.2%	2.6%
Commercial and Industrial	15,672	15,032	4.3	2.5
Public Authority	200	189	6.2	0.2
Total Retail	22,479	21,503	4.5	2.6
Wholesale	3,780	2,927	29.1	(3.8)
Total	26,259	24,430	7.5	1.8

* Percentages are calculated using unrounded amounts.

Electric operating revenues increased in 1996, when compared to 1995, primarily due to an overall 4.5% increase in retail sales resulting primarily from customer growth of 2.3%. The increase in wholesale revenues was due to higher economy sales by the Company and power marketing activities of non-regulated subsidiaries. However, these additional sales contributed little to the increase in electric margin. Electric operating revenues increased in 1995, when compared to 1994, primarily due to higher retail sales resulting from customer growth and additional revenues related to collection of QF purchased power capacity costs. Wholesale revenues decreased in 1995, as compared to 1994, as a result of lower wholesale Kwh sales. The demand for wholesale energy during 1995 was negatively impacted by an available supply of low-cost non-firm energy in the region.

The Company and Cheyenne currently have cost adjustment mechanisms which recognize the majority of the effects of changes in fuel used in generation and purchased power costs and allow recovery of such costs on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1996 and 1995, when compared to the respective preceding year, had little impact on net income. However, as discussed in Note 9. Commitments and Contingencies - Regulatory Matters - Merger Rate Filings in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA, in its decision on the Merger, the CPUC modified and replaced the Company's ECA with an ICA, effective October 1, 1996, which allows for a 50%/50% sharing of certain fuel and energy cost increases and decreases among customers and shareholders. The change did not significantly impact the cost recoveries for 1996.

Fuel used in generation expense increased $13.4 million in 1996, when compared to 1995, primarily due to higher generation levels. Fuel used in generation expense decreased $16.1 million during 1995, as compared to the prior year, primarily due to lower coal and coal transportation costs from the renegotiation of certain contracts as generation levels were about the same for both years.

Purchased power expense increased slightly in 1996 primarily due to purchases in connection with the non-regulated power marketing sales. Purchased power expense increased 10.3% in 1995, as compared to 1994, primarily due to increased purchases from QFs as mandated by the CPUC. Electric energy purchased from QFs is over 50% higher per Kwh than that purchased from other suppliers.

Gas Operations

The following table details the annual change in revenues from gas sales and gas purchased for resale as compared to the preceding year:

	Increase (Decrease) From Prior Years	
	1996	1995
	(Thousands of Dollars)	
Revenues from gas sales	11,211	7,281
Gas purchased for resale	483	(5,197)
Net increase in gas sales margin	$ 10,728	$ 12,478

The following table summarizes gas deliveries by major customer classes:

	Millions of Dth Deliveries		% Change * from prior years	
	1996	1995	1996	1995
Residential	86.1	82.2	4.8%	5.4%
Commercial	50.1	50.5	(0.7)	3.6
Wholesale	1.6	0.3	**	(38.0)
Non-regulated gas marketing	21.8	0.2	**	**
Total Sales	159.6	133.2	19.8	4.8
Transportation, gathering and processing	91.4	77.1	18.6	(15.8)
Total	251.0	210.3	19.4	(3.8)

* Percentages are calculated using unrounded amounts.

** Percentage change is significant, but presentation of the amount is not meaningful.

Gas sales margin increased in 1996, when compared to 1995, primarily due to higher retail gas sales resulting from customer growth of 3.4% and slightly colder weather. Increased gas marketing activities by non-regulated subsidiaries favorably impacted gas sales margin in 1996. Gas sales margin increased in 1995, as compared to 1994, primarily due to higher retail gas sales resulting from colder weather and moderate customer growth; there were approximately 17% more heating degree days in 1995 than in 1994.

Gas transportation, gathering and processing revenues increased $4.7 million in 1996, as compared to 1995, primarily due to an increase in transport deliveries resulting from the shifting of various Company commercial customers to firm transport customers which accelerated in October 1995 with the implementation of new gas rates. Transportation, gathering and processing revenues decreased $7.6 million in 1995 primarily due to the sale of WGG in August 1994 (See Note 4. Acquisition and Divestiture of Investments in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

The Company and Cheyenne have in place GCA mechanisms for natural gas sales, which recognize the majority of the effects of changes in the cost of gas purchased for resale and adjust revenues to reflect such changes in cost on a timely basis. As a result, the changes in revenues associated with these mechanisms in 1996 and 1995, when compared to the respective preceding year, had little impact on net income. However, the fluctuations in gas sales impact the amount of gas the Company must purchase and, therefore, along with increases and decreases in the per-unit cost of gas, affect total gas purchased for resale. In 1996, the increase in the quantity of gas purchased was offset substantially by the lower per unit average cost of gas for the year. The $5.2 million decrease in gas purchased for resale for 1995 is primarily due to lower per unit cost of gas offset, in part, by a slight increase in gas purchases.

Non-Fuel Operating Expenses

Other operating and maintenance expenses decreased $10.1 million during 1996 as compared to 1995, primarily due to the favorable impact of the February 9, 1996 settlement agreement with the DOE resolving all spent nuclear fuel storage and disposal issues at Fort St. Vrain (See Note 2. Fort St. Vrain. in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA), lower labor and employee benefit costs resulting from the hiring freeze instituted in August 1995 and other general cost reductions resulting from the Company's cost containment efforts. These reductions were offset, in part, by higher operating costs from non-regulated operations that were, for the most part, initiated during 1996.

Other operating and maintenance expenses decreased $26.1 million in 1995, as compared to 1994, primarily due to lower labor and employee benefit costs resulting from the Company's cost containment efforts which included the restructuring and downsizing accomplished in 1994 (approximately a $26 million reduction) and the recognition of approximately $8.7 million of involuntary severance costs in 1994. This restructuring and downsizing was completed in two phases: 1) effective April 1, 1994, the Company reduced its workforce by approximately 550 employees through an early retirement/severance program, and 2) during the last six months of 1994, the Company eliminated approximately 550 management and staff level positions in connection with an internal restructuring and involuntary severance program. These decreases in 1995 were offset, in part, by the $2.5 million write-off of software costs due to the cancellation of a materials management project, three months of additional amortization of the early retirement/severance program costs totaling $2.2 million and $2.2 million of additional repair costs associated with an early winter snow storm.

During 1994, the Company recognized additional expenses aggregating approximately $43.4 million for increased costs associated with the defueling and decommissioning of Fort St. Vrain and the impairment of certain Fort St. Vrain related property and inventory. The additional expense was primarily associated with radiation levels in the reactor core being higher than originally anticipated and increased uncertainty related to spent fuel disposal issues (See Note 2. Fort St. Vrain in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Depreciation and amortization expense increased $13.3 million in 1996 and $2.3 million in 1995 primarily due to higher depreciation expense from property additions and amortization of software costs.

Taxes (other than income taxes) decreased $5.1 million in 1995 primarily due to lower payroll related taxes resulting from the 1994 downsizing.

Income taxes increased $1.0 million in 1996, as compared to 1995, primarily due to higher pre-tax income, offset, in part, by the write-off of additional investment tax credits for retired property and additional tax benefits at PSRI. The $46.9 million increase in income taxes during 1995, as compared to 1994, is primarily due to higher pre-tax income and the effects of two items recorded in 1994 which served to lower tax expense during that period. These items included: 1) an adjustment associated with the adoption of full normalization which was provided for in a CPUC rate order (approximately $21.3 million), and 2) the true-up of the tax accrual related to the filing of the 1993 tax return (approximately $5.1 million).

Other income and deductions decreased $15.2 million during 1996, as compared to the preceding year, primarily due to higher costs related to the Merger ($3.1 million), the recognition of $4.1 million of certain severance costs, the recognition of $2.3 million of costs associated with the settlement of environmental issues related to the operations of the Hayden station and a decrease in the allowance for equity funds used during construction. Other income and deductions decreased $34.7 million in 1995 primarily due to the net effects of the pre-tax gain of approximately $34.5 million recognized on the sale of WGG in 1994 (See Note 4. Acquisition and Divestiture of Investments in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA) and $4.0 million of costs related to the Merger (See Note 3. Merger in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA), offset, in part, by the 1994 reversal of the $3.0 million gas search award, as the Colorado Supreme Court reversed the incentive award previously granted by the CPUC.

Interest charges increased $6.0 million during 1996, as compared to 1995. Higher interest on long-term debt resulted from the financing of capital expenditures. Interest charges increased $11.8 million during 1995 as compared to 1994. Other interest increased due to higher interest rates and an increased level of short-term borrowings in 1995, the recognition of interest costs related to the over-collection of expenses under the Company's cost adjustment mechanisms and higher interest on COLI contracts, while the net costs associated with long-term debt decreased slightly.

Financial Position

Accounts receivable increased at December 31, 1996, as compared to 1995, primarily due to overall sales growth, including marketing activities by non-regulated subsidiaries, and the fact that a portion of the gas refund made late in 1995 was applied directly to customers' accounts, which served to lower the accounts receivable balance at December 31, 1995. Accounts payable increased primarily due to the Company's higher gas costs at the end of 1996 and increased activities by non-regulated subsidiaries.

The $38.5 million decrease in the defueling and decommissioning liability was due to expenditures during 1996. This decrease and the increase in noncurrent investments and receivables were also affected by the February 9, 1996 settlement agreement with the DOE resolving all spent nuclear fuel storage and disposal issues at Fort St. Vrain. Customers' advances for construction decreased by approximately $49.3 million due to a 1996 transfer of amounts to property, plant and equipment, which served to reduce such investments, after determining that these amounts would not be refunded to customers in the future.

Commitments and Contingencies

Issues relating to regulatory and environmental matters are discussed in Note 9. Commitments and Contingencies in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA. These matters and the future resolution thereof, may impact the Company's future results of operations, financial position and cash flows.

Common Stock Dividend

In the first quarter of 1996, the Company increased the quarterly dividend on its common stock from $0.51 per share to $0.525 per share. This follows the 1995 first quarter increase in the quarterly dividend on its common stock from $0.50 per share to $0.51 per share. The Company's common stock dividend level is dependent upon the Company's results of operations, financial position, cash flow and other factors. The Board of Directors will continue to evaluate the common stock dividend level on a quarterly basis.

Liquidity and Capital Resources

Cash Flows

	1996	1995	1994
Net cash provided by operating activities (*in millions*) ..	$327.6	$385.7	$245.7

Net cash provided by operating activities decreased $58.1 million in 1996 primarily due to the undercollection of purchased gas and electric energy costs ($40.8 million) and lower cash receipts because of a gas refund that was applied directly to customers' accounts in late 1995. Higher earnings and lower decommissioning and defueling expenditures positively impacted operating cash flows for both 1996 and 1995. The increase in 1995 was also significantly impacted by the overcollection of purchased gas and electric costs.

At December 31, 1996, the Company's decommissioning liability, excluding defueling, was approximately $6.6 million. The remaining expenditures related to this obligation are expected to be incurred over the next year. The annual decommissioning amount being recovered from customers is approximately $13.9 million which will continue through June 2005. At December 31, 1996, approximately $89.7 million remains to be collected from customers and is reflected as a regulatory asset on the consolidated balance sheet.

	1996	1995	1994
Net cash used in investing activities (*in millions*)	$(307.1)	$(284.6)	$(177.4)

Net cash used in investing activities, which substantially consisted of construction expenditures, was higher in both 1996 and 1995, compared to the respective prior years. Proceeds from the sale of WGG in 1994 and the sale of certain Fuelco properties in 1994 and 1996 reduced the net cash used in investing activities (See Note 4. Acquisition and Divestiture of Investments in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

	1996	1995	1994
Net cash used in financing activities (*in millions*)	$(25.8)	$(92.3)	$(80.5)

Net cash used in financing activities decreased (indicating that there were more borrowings) significantly in 1996 primarily due to the issuance of additional long-term debt, including the $125 million First Collateral Trust Bonds in May 1996 and $75 million in medium-term notes in November 1996. The proceeds were used to fund the Company's construction program, for other general corporate purposes and to repay short-term indebtedness incurred for such purposes. Cash used in financing activities increased slightly in 1995 over 1994. Proceeds from the sale of common stock under the Company's dividend reinvestment and stock purchase plan decreased in 1995. Long-term debt refinancing activity also decreased in 1995, as compared to 1994, as a result of higher interest rates. The use of short-term borrowing over the last several years has increased slightly, however, short-term borrowing levels were reduced in late 1995 with an issuance of $80 million of medium-term notes by PSCCC.

Prospective Capital Requirements

At December 31, 1996, the Company and its subsidiaries estimated cost of their construction programs and other capital requirements for the years 1997, 1998 and 1999 are shown in the table below:

	1997	1998	1999
		(Thousands of Dollars)	
Company:			
Electric			
Production *	$ 95,056	$ 103,211	$ 125,505
Transmission	39,600	48,433	22,718
Distribution	68,944	70,426	68,090
Gas	62,991	88,240	56,172
General**	53,440	59,186	21,137
Total Company	320,031	369,496	293,622
Subsidiaries	7,015	6,243	6,075
Total construction expenditures	327,046	375,739	299,697
Less: AFDC	5,640	5,000	6,113
Add: Sinking funds and debt maturities and refinancings	157,851	72,901	120,957
Add: Fort St. Vrain decommissioning	2,500	-	-
Total capital requirements	$ 493,037	$ 453,640	$ 426,767

* Capital requirements for Electric Production include approximately $121 million for Fort St. Vrain repowering and approximately $70 million for pollution control equipment at Hayden.

** Capital requirements in the "General" category include assets leased under a leasing program. The 1997 and 1998 amounts include approximately $40 million of expenditures for automated electric and gas meter reading equipment.

The construction programs of the Company and its subsidiaries are subject to continuing review and modification. In particular, actual construction expenditures may vary from the estimates due to changes in the

electric system 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, the proposed merger with SPS, the Company's ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, and future requirements to install pollution control equipment may impact actual capital requirements (See Note 3. Merger, Note 4. Acquisition and Divestiture of Investments and Note 9. Commitments and Contingencies - Environmental Issues in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

Capital Sources

At December 31, 1996, the Company and its subsidiaries estimated that their 1997-1999 capital requirements will be met principally with a combination of funds from external sources and funds from operations. The Company and its subsidiaries may meet their external capital requirements through the issuance of first collateral trust bonds, preferred and/or common stock, by increasing the level of borrowing under PSCCC's medium-term note program or through the issuance of commercial paper or through short-term borrowing under committed and uncommitted bank borrowing arrangements discussed below. The financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the construction programs and other capital requirements of the Company and its subsidiaries.

Registration Statements

On August 30, 1995, the Company filed a registration statement with the SEC for the issuance of 3 million shares of common stock and 3 million rights to purchase common stock appurtenant thereto to be issued under the Company's Automatic Dividend Reinvestment and Common Stock Purchase Plan ("Dividend Reinvestment Plan") for the purpose of funding its construction program and other general corporate purposes. The Dividend Reinvestment Plan allows its shareholders to purchase additional shares of the Company's common stock through the reinvestment of cash dividends and the purchase of additional shares of common stock with optional cash payments.

In 1994, the Company filed a registration statement with the SEC for the issuance of First Collateral Trust Bonds and cumulative preferred stock for the purpose of funding its construction program, refunding certain issues of its cumulative preferred stock and other general corporate purposes. The aggregate principal amount of first collateral trust bonds, plus the aggregate par value of shares of cumulative preferred stock, will not exceed $306 million. On May 31, 1996, the Company issued $125 million aggregate principal amount of its First Collateral Trust Bonds.

On October 24, 1996, the Company filed a registration statement with the SEC for the issuance of $400 million aggregate principal amount of First Collateral Trust Bonds through one or more series of medium-term notes. On November 13, 1996, the Company established a $250 million Secured Medium-Term Note Program, Series B. As of January 31, 1997, $150 million of the Series B medium-term notes had been issued.

Company's Indentures

The Company's Indenture dated as of December 1, 1939 (the "1939 Indenture"), which is a mortgage on the Company's electric and gas properties, permits the issuance of additional first mortgage bonds to the extent of 60% of the value of net additions to the Company's utility property, provided net earnings before depreciation, taxes on income and interest expense for a recent twelve month period are at least 2.5 times the annual interest requirements on all bonds to be outstanding. The 1939 Indenture also permits the issuance of additional bonds on the basis of retired first mortgage bonds, in some cases with no requirement to satisfy such net earnings test. At December 31, 1996, the amount of net additions would permit (and the net earnings test would not prohibit) the issuance of approximately $365 million of new bonds (in addition to the $250 million principal amount of secured medium-term notes discussed above) at an assumed annual interest rate of 7.80%. At December 31, 1996, the amount of retired bonds would permit the issuance of $718.2 million of new bonds.

The Company's Indenture dated as of October 1, 1993 (the "1993 Indenture") is a second mortgage on the Company's electric properties. Generally, so long as the Company's 1939 Indenture remains in effect, first collateral trust bonds will be issued under the 1993 Indenture on the basis of the deposit with the trustee of an equal principal amount of first mortgage bonds issued under the 1939 Indenture. If the bonds issued under the 1939 Indenture are to be issued on the basis of property additions, first collateral trust bonds may be issued under the 1993 Indenture only if net earnings before depreciation, taxes on income, interest expenses and non-recurring charges for a recent twelve-month period are at least 2 times annual interest requirements on all first mortgage bonds (other than bonds held by the trustee under the 1993 Indenture) and all first collateral trust bonds to be outstanding. As of December 31, 1996, coverage under the net earnings test was 5.3 times such annual interest requirements.

Company's Restated Articles of Incorporation

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, 1996, gross income available under this requirement would permit the Company, if allowed under provisions of the Company's Restated Articles of Incorporation, to issue approximately $2.9 billion of additional preferred stock at an assumed annual dividend rate of 6.90%. Coverage of gross income to interest charges was 6.22 at December 31, 1996.

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, 1996, the Company had outstanding unsecured indebtedness, including subsidiary indebtedness with the credit support of the Company, in the amount of $231.2 million. The maximum amount permitted under this limitation was approximately $425.4 million at December 31, 1996.

Short Term Borrowing Arrangements

The Company and certain subsidiaries have available committed and uncommitted lines of credit to meet their short-term cash requirements. The Company, PSCCC, and certain subsidiaries have a credit facility with several banks which provides $300 million in committed bank lines of credit and is used primarily to support the issuance of commercial paper by the Company and PSCCC, and to provide for direct borrowings thereunder. Under the facility Cheyenne, 1480 Welton, Inc., Fuelco, e prime and PSRI are provided access to the credit facility with direct borrowings guaranteed by the Company. At December 31, 1996, $55.3 million remained unused under this facility. Generally, the banks participating in the credit facility would have no obligation to continue their commitments if there has been a material adverse change in the consolidated financial condition, operations, business or otherwise that would prevent the Company and its subsidiaries from performing their obligation under the credit facility. This facility expires on November 17, 2000. Also, the Company has individual arrangements for uncommitted bank lines of credit which totaled $75 million, and all remained unused at December 31, 1996. These individual arrangements expire on December 31, 1997. The Company may borrow under uncommitted preapproved lines of credit upon request; however, the banks have no firm commitment to make such loans (see Note 8. Bank Lines of Credit and Compensating Bank Balances in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA).

PSCCC may periodically issue medium-term notes (in addition to the short-term debt discussed above) to supplement the financing/purchase of the Company's customer accounts receivable and fossil fuel inventories. As of December 31, 1996, PSCCC had issued and had outstanding $100 million in medium-term notes. 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, and 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.

Item 8. *Financial Statements and Supplementary Data*

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 1996, 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 among Company management, 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, Chairman
Audit Committee

February 24, 1997

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 on Form 10-K is consistent with that in the financial statements.

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

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

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

The Company assessed its internal control system as of December 31, 1996 in relation to criteria for effective internal control over financial reporting described in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of its assessment, the Company believes that, as of December 31, 1996, the Company's system of internal control over external financial reporting, including the safeguarding of assets against unauthorized acquisition, use or disposition, met those criteria.

W. Wayne Brown
Principal Accounting Officer

Wayne H. Brunetti
Chief Executive Officer

February 24, 1997

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO 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, 1996 and 1995, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 1996. These financial statements and the schedule referred to below are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule 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, 1996 and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

As more fully discussed in Note 11 to the consolidated financial statements, effective January 1, 1994, the Company changed its method of accounting for postemployment benefits.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule listed in the index of financial statements is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in our audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

We have also audited, in accordance with generally accepted auditing standards, the consolidated balance sheets as of December 31, 1994, 1993 and 1992 and the related consolidated statements of income, shareholders' equity and cash flows for each of the two years in the period ended December 31, 1993, (none of which are presented herein) and have expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the selected financial data for each of the five years in the period ended December 31, 1996 appearing in Item 6 of this Form 10-K, other than the ratios and percentages therein, is fairly stated, in all material respects, in relation to the financial statements from which it has been derived.

ARTHUR ANDERSEN LLP

Denver, Colorado
February 24, 1997

PUBLIC SERVICE COMPANY OF COLORADO
AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)
December 31, 1996 and 1995

ASSETS

	1996	1995
Property, plant and equipment, at cost:		
Electric	$ 3,931,413	$ 3,751,321
Gas	1,035,394	989,215
Steam and other	78,225	88,446
Common to all departments	418,262	380,809
Construction in progress	181,597	192,580
	5,644,891	5,402,371
Less: accumulated depreciation	2,045,996	1,921,659
Total property, plant and equipment	3,598,895	3,480,712
Investments, at cost, and receivables	46,550	21,776
Current assets:		
Cash and temporary cash investments	9,406	14,693
Accounts receivable, less reserve for uncollectible accounts ($4,049 at December 31, 1996; $3,630 at December 31, 1995) (Schedule II)	218,132	124,731
Accrued unbilled revenues (Note 1)	85,894	96,989
Recoverable purchased gas and electric energy costs - net (Note 1)	31,288	-
Materials and supplies, at average cost	48,972	56,525
Fuel inventory, at average cost	24,739	35,654
Gas in underground storage, at cost (LIFO)	42,826	44,900
Current portion of accumulated deferred income taxes (Note 13)	-	19,229
Regulatory assets recoverable within one year (Note 1)	44,110	40,247
Prepaid expenses and other	41,790	35,619
Total current assets	547,157	468,587
Deferred charges:		
Regulatory assets (Note 1)	304,456	321,797
Unamortized debt expense	10,975	10,460
Other	64,615	48,457
Total deferred charges	380,046	380,714
	$ 4,572,648	$ 4,351,789

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

PUBLIC SERVICE COMPANY OF COLORADO AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)
December 31, 1996 and 1995

CAPITAL AND LIABILITIES

	1996	1995
Common stock (Note 5)	$ 1,048,447	$ 997,106
Retained earnings	389,841	346,539
Total common equity	1,438,288	1,343,645
Preferred stock (Note 5):		
Not subject to mandatory redemption	140,008	140,008
Subject to mandatory redemption at par	39,913	41,289
Long-term debt (Note 6)	1,259,528	1,195,553
	2,877,737	2,720,495
Noncurrent liabilities:		
Employees' postretirement benefits other than pensions (Note 11)	55,677	49,198
Employees' postemployment benefits (Note 11)	25,182	23,500
Defueling and decommissioning liability (Note 2)	-	23,115
Total noncurrent liabilities	80,859	95,813
Current liabilities:		
Notes payable and commercial paper (Note 7)	244,725	288,050
Long-term debt due within one year	155,030	82,836
Preferred stock subject to mandatory redemption within one year (Note 5)	2,576	2,576
Accounts payable	254,256	156,109
Dividends payable	36,973	35,284
Recovered purchased gas and electric energy costs - net (Note 1)	-	9,508
Customers' deposits	21,441	17,462
Accrued taxes	58,990	55,393
Accrued interest	33,797	32,071
Current portion of defueling and decommissioning liability (Note 2)	8,665	24,055
Current portion of accumulated deferred income taxes (Note 13)	4,560	-
Other	69,203	78,451
Total current liabilities	890,216	781,795
Deferred credits:		
Customers' advances for construction	50,269	99,519
Unamortized investment tax credits	105,928	113,184
Accumulated deferred income taxes (Note 13)	539,082	508,143
Other	28,557	32,840
Total deferred credits	723,836	753,686
Commitments and contingencies (Note 9)		
	$ 4,572,648	$ 4,351,789

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

PUBLIC SERVICE COMPANY OF COLORADO AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(Thousands of Dollars, Except per Share Data)
Years ended December 31, 1996, 1995 and 1994

	1996	1995	1994
Operating revenues:			
Electric	$ 1,488,990	$ 1,449,096	$ 1,399,836
Gas	640,497	624,585	624,922
Other	41,899	36,920	32,626
	2,171,386	2,110,601	2,057,384
Operating expenses:			
Fuel used in generation	195,442	181,995	198,118
Purchased power	490,428	481,958	437,087
Gas purchased for resale	393,163	392,680	397,877
Other operating expenses	336,100	346,026	369,094
Maintenance	63,908	64,069	67,097
Defueling and decommissioning (Note 2)	-	-	43,376
Depreciation and amortization	154,631	141,380	139,035
Taxes (other than income taxes)	82,899	81,319	86,408
Income taxes (Note 13)	96,331	95,357	48,500
	1,812,902	1,784,784	1,786,592
Operating income	358,484	325,817	270,792
Other income and deductions:			
Allowance for equity funds used during construction	757	3,782	3,140
Gain on sale of WestGas Gathering, Inc. (Note 4)	-	-	34,485
Miscellaneous income and deductions - net (Notes 1 and 3)	(19,015)	(6,837)	(6,014)
	(18,258)	(3,055)	31,611
Interest charges:			
Interest on long-term debt	92,205	85,832	89,005
Amortization of debt discount and expense less premium	3,621	3,278	3,126
Other interest	57,398	58,109	44,021
Allowance for borrowed funds used during construction	(3,344)	(3,313)	(4,018)
	149,880	143,906	132,134
Net income	190,346	178,856	170,269
Dividend requirements on preferred stock	11,848	11,963	12,014
Earnings available for common stock	$ 178,498	$ 166,893	$ 158,255
Shares of common stock outstanding (thousands):			
Year-end	64,819	63,358	62,155
Weighted average	64,187	62,932	61,547
Earnings per weighted average share of common stock outstanding	$2.78	$2.65	$2.57

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

PUBLIC SERVICE COMPANY OF COLORADO
AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Thousands of Dollars, Except Share Information)
Years ended December 31, 1996, 1995 and 1994

	Common Stock, $5 par value		Premium on	Retained	
	Shares	Amount	Common Stock	Earnings	Total
Balance at December 31, 1993	60,457,375	$ 302,287	$ 608,561	$ 273,335	$ 1,184,183
Net income	-	-	-	170,269	170,269
Dividends declared					
Common stock, $2.00 per share	-	-	-	(123,379)	(123,379)
Preferred stock, $100 par value	-	-	-	(9,071)	(9,071)
Preferred stock, $25 par value	-	-	-	(2,940)	(2,940)
Issuance of common stock					
Employees' Savings Plan	334,223	1,671	8,439	-	10,110
Dividend Reinvestment Plan	1,355,104	6,775	31,308	-	38,083
Omnibus Incentive Plan	7,892	39	188	-	227
Balance at December 31, 1994	62,154,594	310,772	648,496	308,214	1,267,482
Net income	-	-	-	178,856	178,856
Dividends declared					
Common stock, $2.04 per share	-	-	-	(128,587)	(128,587)
Preferred stock, $100 par value	-	-	-	(9,004)	(9,004)
Preferred stock, $25 par value	-	-	-	(2,940)	(2,940)
Issuance of common stock					
Employees' Savings Plan	310,546	1,553	8,152	-	9,705
Dividend Reinvestment Plan	889,331	4,447	23,575	-	28,022
Omnibus Incentive Plan	3,657	19	92	-	111
Balance at December 31, 1995	63,358,128	316,791	680,315	346,539	1,343,645
Net income	-	-	-	190,346	190,346
Dividends declared					
Common stock, $2.10 per share	-	-	-	(135,111)	(135,111)
Preferred stock, $100 par value	-	-	-	(8,889)	(8,889)
Preferred stock, $25 par value	-	-	-	(2,940)	(2,940)
Issuance of common stock					
Employees' Savings Plan	274,934	1,374	8,420	-	9,794
Dividend Reinvestment Plan	809,603	4,048	24,580	-	28,628
Omnibus Incentive Plan	58,346	292	1,427	-	1,719
Acquisitions (Note 4)	317,748	1,589	9,611	-	11,200
Capital Stock Expense	-	-	-	(104)	(104)
Balance at December 31, 1996	64,818,759	$ 324,094	$ 724,353	$ 389,841	$ 1,438,288

Authorized shares of common stock were 160 million at December 31, 1996, 1995 and 1994.

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

PUBLIC SERVICE COMPANY OF COLORADO AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)
Years ended December 31, 1996, 1995 and 1994

	1996	1995	1994
Operating activities:			
Net income	$ 190,346	$ 178,856	$ 170,269
Adjustments to reconcile net income to net cash provided by operating activities (Note 1):			
Depreciation and amortization	159,400	145,370	142,843
Defueling and decommissioning expenses	-	-	43,376
Gain on sale of WestGas Gathering, Inc.	-	-	(34,485)
Amortization of investment tax credits	(7,256)	(5,348)	(5,799)
Deferred income taxes	60,899	39,170	34,234
Allowance for equity funds used during construction	(757)	(3,782)	(3,140)
Change in accounts receivable	(88,680)	38,734	(16,281)
Change in inventories	20,542	4,246	10,007
Change in other current assets	(31,169)	7,618	(1,695)
Change in accounts payable	88,473	(20,922)	(35,364)
Change in other current liabilities	(36,615)	24,230	(39,730)
Change in deferred amounts	(19,550)	(20,385)	(33,920)
Change in noncurrent liabilities	(9,779)	(5,367)	15,321
Other	1,760	3,279	92
Net cash provided by operating activities	327,614	385,699	245,728
Investing activities:			
Construction expenditures	(321,162)	(285,516)	(317,138)
Allowance for equity funds used during construction	757	3,782	3,140
Proceeds from sale of WestGas Gathering, Inc.	-	-	87,000
Proceeds from disposition of property, plant and equipment	20,454	2,470	49,438
Payment for purchase of companies, net of cash acquired (Note 4)	3,649	-	-
Purchase of other investments	(11,485)	(10,249)	(955)
Sale of other investments	664	4,898	1,148
Net cash used in investing activities	(307,123)	(284,615)	(177,367)
Financing activities:			
Proceeds from sale of common stock (Note 1)	30,115	28,030	38,086
Proceeds from sale of long-term notes and bonds (Note 1)	217,415	101,860	250,068
Redemption of long-term notes and bonds	(83,356)	(44,713)	(281,835)
Short-term borrowings - net	(43,325)	(36,750)	47,925
Redemption of preferred stock	(1,376)	(1,376)	(213)
Dividends on common stock	(133,394)	(127,352)	(122,531)
Dividends on preferred stock	(11,857)	(11,973)	(12,016)
Net cash used in financing activities	(25,778)	(92,274)	(80,516)
Net increase (decrease) in cash and temporary cash investments	(5,287)	8,810	(12,155)
Cash and temporary cash investments at beginning of year	14,693	5,883	18,038
Cash and temporary cash investments at end of year	$ 9,406	$ 14,693	$ 5,883

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

PUBLIC SERVICE COMPANY OF COLORADO
AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 1996

1. Summary of Significant Accounting Policies

Business, utility operations and regulation

The Company is an operating public utility engaged, together with its utility subsidiaries, principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transmission, distribution, sale and transportation of natural gas. The Company is subject to the jurisdiction of the CPUC with respect to its retail electric and gas operations and the FERC with respect to its wholesale electric operations and accounting policies and practices. Over 90% of the Company's electric and gas revenues are subject to CPUC jurisdiction. Cheyenne is subject to the jurisdiction of the WPSC. WGI and TOP are subject to the jurisdiction of the FERC. The gas marketing, power brokering and other operations of e prime and TOG are not regulated.

Regulatory assets and liabilities

The Company and its regulated subsidiaries prepare their financial statements in accordance with the provisions of SFAS 71, as amended. SFAS 71 recognizes that accounting for rate regulated enterprises should reflect the relationship of costs and revenues introduced by rate regulation. A regulated utility may defer recognition of a cost (a regulatory asset) or recognize an obligation (a regulatory liability) if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in revenues. On January 1, 1996, the Company adopted SFAS 121 which imposes stricter criteria for the continued recognition of regulatory assets on the balance sheet by requiring that such assets be probable of future recovery at each balance sheet date. The adoption of this statement did not have a material impact on the Company's results of operations, financial position or cash flow. The following regulatory assets are reflected in the Company's consolidated balance sheets:

	1996	1995	Recovery Through
	(Thousands of Dollars)		
Nuclear decommissioning costs (Note 2)	$ 89,731	$ 97,801	2005
Income taxes (Note 13)	98,355	110,617	2006
Employees' postretirement benefits other than pensions (Note 11)	54,449	47,600	2013
Early retirement costs (Note 11)	15,505	24,366	1998
Employees' postemployment benefits (Note 11)	24,797	23,500	Undetermined
Demand-side management costs	41,462	30,188	2002
Unamortized debt reacquisition costs	19,914	21,940	2024
Other	4,353	6,032	1999
Total	348,566	362,044	
Classified as current	44,110	40,247	
Classified as noncurrent	$304,456	$321,797	

Certain costs associated with the Company's DSM programs are deferred and recovered, along with the associated return, in rates over five to seven year periods through the DSMCA. Non-labor incremental expenses, carrying costs associated with deferred DSM costs and incentives associated with approved DSM programs are recovered on an annual basis. Costs incurred to reacquire debt prior to scheduled maturity dates are deferred and amortized over the life of the debt issued to finance the reacquisition or as approved by the applicable regulatory authority.

The regulatory assets of the Company and its regulated subsidiaries as of December 31, 1996, are reflected in rates charged to customers over the recovery periods noted above. The Company believes it will continue to be subject to rate regulation. In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 71 as a result of a change in regulation or the effects of competition, the Company could be required to write-off related regulatory assets, determine any impairment to other assets resulting from deregulation and write-down any impaired assets to their estimated fair value.

On January 27, 1997, the CPUC issued its order on the Company's 1996 gas rate case. The CPUC allowed recovery of postemployment benefit costs on an accrual basis under SFAS 112 and denied amortization of the approximately $8.7 million regulatory asset recognized upon the adoption of SFAS 112 (see Note 11. Employee Benefits - Postemployment Benefits). The Company is appealing the decision related to this issue and addressing the impact of this decision on the future recovery of the electric jurisdictional portion of postemployment benefit costs totaling approximately $13.8 million. The Company believes that it will be successful on appeal and that the associated regulatory asset is realizable. If the appeal is unsuccessful, these amounts will be written off.

Recovered/Recoverable purchased gas and electric energy costs - net

The Company's and Cheyenne's tariffs contain clauses which allow recovery of certain purchased gas and electric energy costs in excess of the level of such costs included in base rates. Currently, these cost adjustment tariffs are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. The cumulative effects are recognized as a current asset or liability until adjusted by refunds or collections through future billings to customers. The CPUC's order related to the Company's merger rate filing modified and replaced the Company's ECA with an ICA, which allows for a 50%/50% sharing of certain fuel and energy cost increases and decreases among customers and shareholders (see Note 9. Commitments and Contingencies - Regulatory Matters).

Other property

Property, plant and equipment includes approximately $18.4 million and $25.4 million, respectively, for costs associated with the engineering design of the future Pawnee 2 generating station and certain water rights located in southeastern Colorado, also obtained for a future generating station. The Company is earning a return on these investments based on the Company's weighted average cost of debt and preferred stock in accordance with a CPUC rate order.

Non-utility subsidiaries

The Company's net investment in its non-utility subsidiaries approximated 4.5% of common equity at December 31, 1996. The subsidiaries are principally involved in non-regulated energy services, the management of real estate and certain life insurance policies and the financing of certain current assets of the Company.

Management estimates

The preparation of financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Consolidation

The Company follows the practice of consolidating the accounts of its significant subsidiaries. All intercompany items and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year's presentation.

Revenue recognition

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

Statements of cash flows

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

Income taxes and interest (excluding amounts capitalized) paid:

	1996	1995	1994
		(Thousands of Dollars)	
Income taxes	\$ 66,871	\$ 58,662	\$ 41,763
Interest	\$ 144,533	\$ 140,823	\$ 126,250

Non-cash transactions.

Shares of common stock (274,934 in 1996, 310,546 in 1995 and 334,223 in 1994), valued at the market price on date of issuance (approximately \$10 million for each year), 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. Shares of common stock (6,673 in 1996, 3,390 in 1995 and 7,892 in 1994), valued at the market price on the date of issuance (\$0.2 million in 1996, \$0.1 million in 1995 and \$0.2 million in 1994), were issued to certain executives pursuant to the applicable provisions of the executive compensation plans.

During 1996, the Company exchanged 317,748 shares of its common stock valued at approximately \$11.2 million in connection with the acquisition of TOG. During 1994, the Company sold all of its outstanding common stock of WGG (see Note 4. Acquisition and Divestiture of Investments). Cash flows from operating activities reflect the changes in assets and liabilities, net of the effects from these acquisitions and divestiture.

The stock issuances referenced above were non-cash financing activities and are not reflected in the consolidated statements of cash flows.

A \$40.5 million capital lease obligation was recognized in 1995 in connection with a 30-year gas storage facility agreement. Additionally, other capital lease obligations totaling approximately \$0.1 million were recognized in 1995. A \$16.8 million capital lease obligation was incurred for computer equipment in 1994.

Property, depreciation and amortization

Replacements and betterments representing units of property are capitalized. Maintenance and repairs of property and replacements of items of property determined to be less than a unit of property are charged to operations as maintenance. The cost of units of property retired, together with cost or removal, less salvage, is charged against accumulated depreciation.

Provisions for depreciation of property, plant and equipment for financial accounting purposes are based on straight-line composite rates applied to the various classes of depreciable property. Depreciation rates include provisions for disposal and removal costs of property, plant and equipment. Depreciation expense, expressed as a percentage of average depreciable property, approximated 2.7% for the year ended December 31, 1996 and 2.6% for the years ended December 31, 1995 and 1994. For income tax purposes, the Company and its subsidiaries use accelerated depreciation and other elections provided by the tax laws. Intangible assets are amortized on a straight line basis over their estimated useful lives.

Allowance for funds used during construction

AFDC, as defined in the system of accounts prescribed by the FERC and the CPUC, represents 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. AFDC does not represent current cash earnings. The Company capitalizes AFDC as a part of the cost of utility plant. The AFDC rates or ranges of rates used during 1996, 1995 and 1994 were 5.67%-6.78%, 7.97% and 6.81%-8.75%, respectively.

Miscellaneous income and deductions - net

Miscellaneous income and deductions - net includes items which are non-operating in nature or, in general, are not considered in the ratemaking process. Such items include, among other things, merger related costs, contributions, gains and losses on the sale of property and certain litigation, severance and environmental costs. Individually, these amounts did not have a material impact on the Company's results of operations.

Income taxes

The Company and its subsidiaries file consolidated Federal and state income tax returns. Income taxes are allocated to the subsidiaries based on separate company computations of taxable income or loss. Investment tax credits have been deferred and are being amortized over the service lives of the related property. Deferred taxes are provided on temporary differences between the financial accounting and tax bases of assets and liabilities using the tax rates which are in effect at the balance sheet date (see Note 13. Income Taxes).

Stock-based compensation

As allowed by SFAS 123, the Company uses the intrinsic value based method of accounting prescribed by APB Opinion No. 25, in accounting for its stock-based compensation plan (see Note 11. Employee Benefits - Incentive Compensation).

Gas in underground storage

Gas in underground storage is accounted for under the last-in, first-out (LIFO) cost method. The estimated replacement cost of gas in underground storage at December 31, 1996 and 1995 exceeded the LIFO cost by approximately $52.2 million and $5.3 million, respectively.

Cash surrender value of life insurance policies

The following amounts related to COLI contracts, issued by one major insurance company, are recorded as a component of Investments, at cost and receivables, on the consolidated balance sheets:

	1996	1995
	(Thousands of Dollars)	
Cash surrender value of contracts	$ 359,136	$ 311,097
Borrowings against contracts	356,421	308,833
Net investment in life insurance contracts	$ 2,715	$ 2,264

2. Fort St. Vrain

Overview

In 1989, the Company announced its decision to end nuclear operations at Fort St. Vrain and to proceed with the defueling and decommissioning of the reactor. While the defueling of the reactor to the ISFSI was completed in June 1992, several issues related to the ultimate storage/disposal of Fort St. Vrain's spent nuclear fuel remained unresolved. During 1994, the Company recognized additional expenses aggregating approximately $43.4 million for increased costs associated with defueling and decommissioning and the impairment of certain property and inventory. The additional expense was primarily associated with radiation levels in the reactor core being higher than originally anticipated and increased uncertainty related to spent fuel issues. In 1996, the Company and the DOE entered into a contract resolving all the defueling issues. Additionally, in early 1996, the Company announced that the physical decommissioning work at the facility was completed. NRC site release activities are continuing. The Company requested the NRC to terminate the Part 50 license and it is anticipated that the license will be terminated by mid-1997.

Fort St. Vrain is being repowered as a gas fired combined cycle steam plant consisting of two combustion turbines and two heat recovery steam generators totaling 471 Mw. The CPCN, which was received in July 1994, provides for the repowering of Fort St. Vrain in a phased approach as follows: Phase 1A - 130 Mw, commercial operations commenced on May 1, 1996, Phase 1B - 102 Mw, currently under construction with a 1998 expected in service date and Phase 2 - 239 Mw in 2000. The phased repowering allows the Company flexibility in timing the addition of this generation supply to meet future load growth.

Defueling

On February 9, 1996, the Company and the DOE entered into an agreement relating to the disposal of Fort St. Vrain's spent nuclear fuel. As part of this agreement, the Company has agreed to the following: 1) the DOE assumed title to the fuel currently stored in the ISFSI, 2) the DOE will assume title to the ISFSI and will be responsible for the future defueling and decommissioning of the facility, 3) the DOE agreed to pay the Company $16 million for the settlement of claims associated with the ISFSI, 4) ISFSI operating and maintenance costs, including licensing fees and other regulatory costs, will be the responsibility of the DOE, and 5) the Company provided to the DOE a full and complete release of claims against the DOE resolving all contractual disputes related to storage/disposal of Fort St. Vrain spent nuclear fuel. On December 17, 1996, the DOE submitted a request to the NRC to transfer the title of the ISFSI. This request is being reviewed by the NRC and the Company anticipates approval in mid-1997.

As a result of the DOE settlement, coupled with a complete review of expected remaining decommissioning costs and establishment of the anticipated refund to customers, pre-tax earnings for 1996 were positively impacted by approximately $16 million. In accordance with the 1991 CPUC approval to recover certain decommissioning costs, 50% of any cash amounts received from the DOE as part of a settlement, net of costs incurred by the Company, including legal fees, is to be refunded or credited to customers. While the amount to be refunded to customers has not yet been finally determined, the Company established an $8 million liability for such refunds.

Decommissioning

Following the 1991 CPUC approval, effective July 1, 1993 the Company began collecting from customers decommissioning costs expected to total approximately $124.4 million (plus a 9% carrying cost). Such amount, which is being collected over a twelve year period, represented the inflation-adjusted estimated remaining cost of decommissioning activities not previously recognized as expense at the time of CPUC approval. At December 31, 1996, approximately $89.7 million of such amount remains to be collected from customers and, therefore, is reflected as a regulatory asset on the consolidated balance sheet. The amount recovered from customers each year is approximately $13.9 million.

On March 22, 1996, the Company and the decommissioning contractors announced that the physical decommissioning activities at the facility have been completed. Additionally, the final site survey was completed in late October 1996 with only the NRC site release remaining to be obtained. At December 31, 1996, a remaining $8.7 million defueling and decommissioning liability was reflected on the consolidated balance sheet. The Company believes this remaining decommissioning liability is adequate to complete all final decommissioning activities.

Under NRC regulations, the Company is required to make filings with, and obtain the approval of, the NRC regarding certain aspects of the Company's decommissioning proposals, including funding. On January 27, 1992, the NRC accepted the Company's funding aspects of the decommissioning plan, which for several years included obtaining an unsecured irrevocable letter of credit. In December 1996, the Company placed $8.5 million in a trust to satisfy the remaining funding requirements. These funds are restricted for decommissioning expenditures and any unspent funds will remain in this trust until the NRC releases the Company from further obligation, which is anticipated to occur by mid-1997.

Nuclear Insurance

During commercial operation and defueling, the Company participated in a federally mandated program to provide funding in the event public liability claims arose from a nuclear incident which exceeded available commercial insurance capacity. Under the requirements of the Price-Anderson Act, the Company remains subject to potential assessments of up to $79 million per incident, in amounts not to exceed $10 million per incident per year. The Company was granted an NRC waiver from participation in this program on February 17, 1994 and, therefore, remains subject to assessments levied in response to incidents prior to such date. The Company continues to maintain primary commercial nuclear liability insurance of $100 million for the Fort St. Vrain site and the adjoining ISFSI.

On June 7, 1995, the NRC granted the Company an exemption from the requirement to purchase nuclear property damage and decontamination coverage following an environmental assessment and finding of no significant impact. The Company maintains coverage of $10 million to provide property damage and decontamination protection in the event of an accident involving the ISFSI.

3. Merger

On August 22, 1995, the Company, SPS, a New Mexico corporation, and NCE, a newly formed Delaware corporation, entered into a Merger Agreement providing for a business combination as peer firms involving the Company and SPS in a "merger of equals" transaction. Based on outstanding common stock of the Company and SPS at December 31, 1996, the Merger would result in the common shareholders of the Company owning 63% of the common equity of NCE and the common shareholders of SPS owning 37% of the common equity of NCE. In January 1996, NCE filed its application with the SEC to be a registered public utility holding company and the parent company for the Company and SPS.

The shareholders of the Company and SPS approved the Merger Agreement on January 31, 1996. The Merger is subject to customary closing conditions, including the receipt of all necessary governmental approvals and the making of all necessary governmental filings, including approvals and findings of state utility regulators in Colorado, Texas, New Mexico, Wyoming and Kansas as well as the approval of the FERC, the NRC, the SEC, the Federal Trade Commission and the U.S. Department of Justice in addition to the expiration or termination of the applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 ("HSR"), as amended. The required authorizations from the CPUC, the Public Utility Commission of Texas, the WPSC, the New Mexico Public Utility Commission, the Kansas Corporation Commission, the NRC and the U.S. Department of Justice have been obtained. The waiting period under the HSR Act has expired. Related to FERC approval, a non-unanimous settlement agreement has been reached and hearings were held in late September 1996. On January 23, 1997, the sole party opposing the settlement filed a notice with the FERC withdrawing all of its pleadings. The Company has requested that the FERC give the matter expedited consideration. A final FERC order is expected in March 1997. The Company expects that the SEC will make its ruling on the Merger within 30-60 days following the FERC decision. While timing of the effective

date of the Merger is primarily dependent on the regulatory process, it is currently expected that the Merger will be completed in the second quarter of 1997.

A transition management team, consisting of executives from each company, is working toward the common goal of creating one company with integrated operations to achieve a more efficient and economic utilization of facilities and resources. It is management's intention that NCE begin realizing certain savings upon the consummation of the Merger and, accordingly, costs associated with the Merger and the transition planning and implementation are expected to negatively impact earnings during 1997. The Company recognized costs associated with the Merger of approximately $7.2 million in 1996 and $4.1 million in 1995. The Merger is expected to qualify as a tax-free reorganization and as a pooling of interests for accounting purposes.

The Company recognizes that the divestiture of its existing gas business or certain non-utility ventures is a possibility under the new registered holding company structure proposed as part of the merger with SPS. The Company is seeking approval from the SEC to maintain these businesses and currently does not anticipate that divestiture will be required. If divestiture is ultimately required, the SEC has historically allowed companies sufficient time to accomplish divestitures in a manner that protects shareholder value.

4. Acquisition and Divestiture of Investments

Proposed Acquisition of Yorkshire Electricity

On February 24, 1997, the Company and AEP jointly announced that they have reached agreement with the board of directors of Yorkshire Electricity, a UK regional electricity company, on the terms of a recommended cash tender offer for all of the outstanding and to be issued ordinary shares of Yorkshire Electricity. The Company and AEP, through a joint venture named Yorkshire Holdings, are offering the equivalent of US $15.02 (9.27 pounds) per ordinary share, for a total purchase price of approximately US $2.4 billion (1.5 billion pounds). The boards of directors of the Company and AEP have approved the transaction. The board of directors of Yorkshire Electricity has agreed to recommend the offer to Yorkshire Electricity's shareholders. The offer will be made through Yorkshire Holdings, a wholly-owned subsidiary of Yorkshire Power, a newly formed UK corporation owned equally by the Company and AEP.

Consummation of the Proposed Acquisition is subject to customary conditions in the UK, including regulatory clearance and acceptance of the offer by holders of at least 90% of the outstanding shares of Yorkshire Electricity. Yorkshire Holdings may waive the latter condition when it has received acceptances of its offer and has otherwise acquired shares which in total represent more than 50% of the outstanding shares of Yorkshire Electricity. The Company cannot predict at this time whether or not these conditions will be met or waived.

If the Proposed Acquisition is completed, the Company would have an indirect 50% ownership interest in Yorkshire Electricity, which would be accounted for using the equity method of accounting.

Acquisition of Texas-Ohio Gas, Inc. and Texas-Ohio Pipeline, Inc.

Effective September 1, 1996, the Company and e prime, a wholly-owned subsidiary, acquired all of the outstanding stock of TOG and TOP in exchange for a combination of common stock of the Company and cash. Such acquisitions were accounted for using the purchase method and the acquired assets and liabilities have been valued at their estimated fair market values as of the date of acquisition. These companies are primarily engaged in gas brokering and marketing activities and are subsidiaries of e prime.

Divestiture of Fuel Resources Development Co.

Since 1993, the Company has been pursuing the divestiture of all properties owned by Fuelco, a wholly-owned subsidiary which was primarily involved in the exploration and production of oil and natural gas. The Company recognized the estimated effects of the divestiture in the fourth quarter of 1993 and sold the remaining properties in 1994 and 1996 at approximately net book value.

WestGas TransColorado, Inc.

In September 1995, WGT sold its one-third interest in the TransColorado Gas Transmission Company for $3.8 million, which approximated net book value.

Acquisition of Young Gas Storage Company

On June 25, 1995, the Company acquired all of the outstanding stock of YGSC for $6.3 million. The acquisition was accounted for using the purchase method. On February 1, 1996, the Company contributed the common stock of YGSC to e prime. YGSC owns a 47.5% general partnership interest in Young Storage, which owns and operates an underground facility in northeastern Colorado.

Sale of WestGas Gathering, Inc.

In August 1994, the Company sold all of its outstanding common stock of WGG, its wholly-owned subsidiary, and certain related operating assets of the Company which were used by WGG for approximately $87 million, subject to certain final closing adjustments. The Company recognized a pre-tax gain of approximately $34.5 million ($19.5 million after-tax or approximately 31 cents per share). In the first quarter of 1995, the Company recognized $2.1 million of this gain as an amount to be refunded to customers in accordance with a March 30, 1995 settlement with the OCC. The refund was completed in late 1995.

5. Capital Stock

Common Stock

During 1991, the Company's Board of Directors declared a dividend of one common share purchase right ("right") on each outstanding share of the Company's common stock. All 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. These 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. On August 22, 1995, in connection with the proposed merger (see Note 3), the Company's Rights Agreement was amended to provide that NCE will not be considered an "Acquiring Person" as a result of the execution, delivery, and performance of the Merger Agreement.

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 at least 20% but no more than 50% of the Company's common stock, the Company's Board of Directors may exchange each right held by shareholders other than the acquiring person or group for one share of common stock (or its equivalent).

If a person or group successfully acquires 80% of the Company's common stock for cash, after tendering for all of the common stock, and satisfies certain other conditions, the rights would not operate. The rights expire

on March 22, 2001; however, each right may be redeemed by the Board of Directors for one cent at any time prior to the acquisition of 20% of the common stock by a potential acquiror.

Preferred Stock

	1996		1995	
	Shares	Amount (Thousands of Dollars)	Shares	Amount (Thousands of Dollars)
Cumulative preferred stock, $100 par value:				
Authorized	3,000,000		3,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
4.20% series	100,000	$ 10,000	100,000	$ 10,000
4 1/4% series (includes $7,500 premium)	175,000	17,508	175,000	17,508
4 1/2% series	65,000	6,500	65,000	6,500
4.64% series	160,000	16,000	160,000	16,000
4.90% series	150,000	15,000	150,000	15,000
4.90% 2nd series	150,000	15,000	150,000	15,000
7.15% series	250,000	25,000	250,000	25,000
Total	1,050,000	$ 105,008	1,050,000	$ 105,008
Subject to mandatory redemption:				
7.50% series	216,000	$ 21,600	216,000	$ 21,600
8.40% series	208,892	20,889	222,652	22,265
	424,892	42,489	438,652	43,865
Less: Preferred stock subject to mandatory redemption within one year	(25,760)	(2,576)	(25,760)	(2,576)
Total	399,132	$ 39,913	412,892	$ 41,289
Cumulative preferred stock, $25 par value:				
Authorized	4,000,000		4,000,000	
Issued and outstanding:				
Not subject to mandatory redemption:				
8.40% series	1,400,000	$ 35,000	1,400,000	$ 35,000

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

Cumulative preferred stock, not subject to mandatory redemption:

$100 par value, all series: $101 per share.
$25 par value, 8.40% series: $25.25 per share.

Cumulative preferred stock, subject to mandatory redemption:

7.50% series: $101.75 per share on or prior to August 31, 1997, reducing each year thereafter by $0.25 per share until August 31, 2003, after which the redemption price is $100 per share; 8.40% series: $102 per share on or prior to July 31, 1997, and reducing each year thereafter by $0.25 per share until July 31, 2004, after which the redemption price is $100 per share.

In 1997 and in each year thereafter, the Company must offer to repurchase 12,000 shares of the 7.50% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase, and 13,760 shares of the 8.40% series subject to mandatory redemption at $100 per share, plus accrued dividends to the date set for repurchase. Consequently, this preferred stock to be redeemed is classified as preferred stock

subject to mandatory redemption within one year in the December 31, 1996 consolidated balance sheet. In 1996 and 1995, the Company repurchased 13,760 shares of the 8.40% cumulative preferred series subject to mandatory redemption. In 1994, the Company repurchased 2,133 shares of the 8.40% cumulative preferred series subject to mandatory redemption. No other changes in preferred stock occurred in the three years ended December 31, 1996.

6. Long-Term Debt

	1996	1995
	(Thousands of Dollars)	
Public Service Company of Colorado:		
First Collateral Trust Bonds:		
6% series, due January 1, 2001	$ 102,667	$ 102,667
6 3/8% series, due November 1, 2005	134,500	134,500
7 1/8% series, due June 1, 2006	125,000	-
7 1/4% series, due January 1, 2024	110,000	110,000
First Mortgage Bonds:		
5 7/8% - 6 3/4% series, due May 1, 1996 - July 1, 1998	60,000	95,000
8 1/8% series, due March 1, 2004	100,000	100,000
8 3/4% - 9 7/8% series, due July 1, 2020 - March 1, 2022	225,000	225,000
Pollution Control Series A, 5 7/8%, due March 1, 2004	22,500	23,000
Pollution Control Series F, 7 3/8%, due November 1, 2009	27,250	27,250
Pollution Control Series G, 5 5/8% - 5 7/8%, due April 1, 2008 - April 1, 2014	79,500	79,500
Pollution Control Series H, 5 1/2%, due June 1, 2012	50,000	50,000
Secured Medium-Term Notes, Series A:		
6.05% - 9.25%, due Jan 15, 1996 - November 25, 2003	183,500	151,500
Unamortized premium	13	24
Unamortized discount	(5,032)	(4,568)
Capital lease obligations, 6.68-14.65%, due in installments through May 31, 2025	49,070	53,567
	1,263,968	1,147,440
Cheyenne Light, Fuel and Power Company:		
First Mortgage Bonds:		
7 7/8% series, due April 1, 2003	4,000	4,000
7.50% series, due January 1, 2024	8,000	8,000
Industrial Development Revenue Bonds, 7.25%, due September 1, 2021	7,000	7,000
PS Colorado Credit Corporation, Inc.:		
Unsecured Medium-Term Notes, Series A:		
5.75% - 6.03%, due November 24, 1997 - December 1, 1998	100,000	80,000
1480 Welton, Inc.:		
13.25% secured promissory note, due in installments through October 1, 2016	31,506	31,814
Natural Fuels Corporation:		
Capital lease obligations, 4.21-11.11%, due in installments through November 5, 2000	84	135
	1,414,558	1,278,389
Less: maturities due within one year	155,030	82,836
	$1,259,528	$1,195,553

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. Additionally, there is a second lien on the electric property securing the Company's First Collateral Trust Bonds. The Company's First Collateral Trust Bonds are additionally secured by an equal amount of First Mortgage Bonds which bear no interest.

The aggregate annual maturities and sinking fund requirements during the five years subsequent to December 31, 1996 are (in thousands of dollars):

Year	Maturities	Sinking Fund Requirements	Total
1997	$ 155,030	$ 810	$ 155,840
1998	76,499	560	77,059
1999	44,196	560	44,756
2000	31,656	560	32,216
2001	8,302	560	8,862

The Company and Cheyenne expect to satisfy substantially all of their sinking fund obligations through the application of property additions.

7. Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended December 31, 1996 and 1995 is as follows:

	1996	1995
	(Thousands of Dollars)	
Notes payable to banks (weighted average interest rates of 5.98% at December 31, 1996 and 6.12% at December 31, 1995)...........................	$ 18,375	$ 45,800
Commercial paper (weighted average interest rates of 6.10% at December 31, 1996 and 6.21% at December 31, 1995)...........................	226,350	242,250
	$ 244,725	$ 288,050
Maximum amount outstanding at any month-end during the period.................	$ 306,675	$ 329,475
Weighted average amount (based on the daily outstanding balance) outstanding for the period (weighted average interest rates of 5.63% for the year ended December 31, 1996 and 6.18% for the year ended December 31, 1995)...	$ 250,324	$ 292,226

8. 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.

The Company, PSCCC, and certain subsidiaries have entered into a credit facility with several banks providing $300 million in committed bank lines of credit. The credit facility, which is used primarily to support the issuance of commercial paper by the Company and PSCCC, alternatively provides for direct borrowings thereunder. Cheyenne, 1480 Welton, Inc., Fuelco, e prime and PSRI are provided access to the credit facility with direct borrowings guaranteed by the Company. The facility expires November 17, 2000.

Individual arrangements for uncommitted bank lines of credit totaled $75 million at December 31, 1996, of which all remained unused. The Company may borrow under uncommitted preapproved lines of credit upon request; however, the banks have no firm commitment to make such loans.

9. Commitments and Contingencies

Regulatory Matters

Merger Rate Filings

In connection with the Merger with SPS, in November 1995 the Company filed comprehensive proposals with the CPUC, the WPSC and the FERC to obtain approval of the Merger and the associated comprehensive proposals from such regulatory agencies.

On November 29, 1996, and as modified on January 15, 1997, the CPUC issued a written decision approving the Merger as well the major provisions of a stipulation and agreement entered into among the Company, the CPUC Staff, the OCC, and substantially all other parties. The decision establishes a five year performance based regulatory plan and acknowledges that the Merger is in the public interest. The major provisions of the decision include:

- a $6 million electric rate reduction, which was instituted October 1, 1996, to be followed by an additional $12 million electric rate reduction effective with the implementation of new gas rates on February 1, 1997 resulting from the 1996 general gas rate case,
- an annual electric department earnings test with the sharing of earnings in excess of an 11% return on equity for the calendar years 1997-2001 as follows:

Electric Department	Sharing of Excess Earnings	
Return on Equity	Customers	Shareholders
11-12%	65%	35%
12-14%	50%	50%
14-15%	35%	65%
over 15%	100%	0%;

- the termination of the QFCCA earnings test which was to become effective on October 1, 1996;
- a freeze in base electric rates for the period through December 31, 2001 with the flexibility to make certain other rate changes, including those necessary to allow for the recovery of DSM, QF and decommissioning costs;
- a replacement of the Company's ECA with an ICA to allow for a 50%/50% sharing of certain fuel and energy cost increases or decreases among customers and shareholders; and
- the implementation of a QSP which provides for penalties totaling up to $5 million in year one and increasing to $11 million in year five, if the Company does not achieve certain performance measures relating to electric reliability, customer complaints and telephone response to inquiries. A new docket is expected to be opened to address the implementation of a reward structure for performance above certain standards.

The rate reductions, the earnings sharing, the QSP and the adoption of an ICA will remain in effect even if the Merger is not consummated. The freeze in base electric rates does not prohibit the Company from filing a general rate case or deny any party the opportunity to initiate a complaint or show cause proceeding.

Approval of the Merger was received from the WPSC on August 16, 1996. Hearings in the FERC proceedings were held in September and a non-unanimous settlement agreement was reached. On January 23, 1997, the sole party opposing the settlement filed a notice with the FERC withdrawing all of its pleadings. The Company has requested that the FERC give the matter expedited consideration. A final FERC order is expected in March 1997.

Rate Cases

On June 5, 1996, the Company filed a retail rate case with the CPUC requesting an annual increase in its jurisdictional gas department revenues of approximately $34 million. Intervenor testimony was filed in the third quarter of 1996 with the primary issue being authorized rate of return on common equity. In January 1997, the CPUC approved an overall increase of $17.6 million with an 11.25% return on equity, effective February 1, 1997. On February 20, 1997, the Company filed for rehearing, reargument and reconsideration on the treatment of certain issues (see Note 1).

The Company filed a rate case with the FERC on December 29, 1995, requesting a slight overall rate increase (less than 1%) from its wholesale electric customers. This filing, among other things, requested approval for recovery of OPEB costs under SFAS 106, postemployment benefit costs under SFAS 112 and new depreciation rates based on the Company's most recent depreciation study. Settlement agreements have been reached with all parties and filed with the FERC which recognized recovery of the benefit costs discussed above and results in an overall slight decrease in rates. A final order is expected to be issued in early 1997.

Electric and Gas Cost Adjustment Mechanisms

During 1994 and 1995, the CPUC conducted several proceedings to review issues related to the ECA. The CPUC opened a docket to review whether the ECA should be maintained in its present form, altered or eliminated, and on January 8, 1996, combined this docket with the merger docket discussed above. The CPUC decision on the Merger modified and replaced the ECA with an ICA. The ICA, which became effective October 1, 1996, allows for a 50%/50% sharing of certain fuel and energy cost increases and decreases among customers and shareholders.

The CPUC has had an on-going docket to review and prescribe a standardized GCA process to determine the prudence of gas commodity and pipeline delivery service costs incurred by gas utilities. Other issues to be addressed in this docket include whether the GCA should be maintained in its present form, altered or eliminated. The CPUC conducted hearings regarding this matter on February 14, 1997. Additional hearings have been scheduled for March 7, 1997.

The CPUC approved the recovery of certain energy efficiency credits from retail jurisdiction customers through the DSMCA in June 1994. The OCC filed an appeal of the CPUC's decision in the Denver District Court. The Denver District Court approved the collection of these credits in June 1995, subject to refund. On April 9, 1996, the Denver District Court issued an order affirming the CPUC's decision, however, the OCC appealed this issue to the Colorado Supreme Court. On August 20, 1996, the OCC filed a motion for voluntary dismissal with prejudice with the Colorado Supreme Court which was accepted and effectively resolved this matter.

Federal Energy Regulatory Commission

On April 24, 1996, the FERC issued Order No. 888, Order No. 889 and a NOPR. Order No. 888 requires jurisdictional utilities owning, controlling, or operating transmission facilities to file non-discriminatory open-access tariffs that satisfy the comparability standard-- i.e., that offer transmission services consistent with what is provided for in their own operations. The FERC required that all such utilities file the single pro forma tariff (combined network and point-to-point tariff) by July 9, 1996. The Company has filed the required pro forma tariff. Order No. 888 also provides for the recovery of legitimate, prudent, and verifiable stranded investment costs incurred when existing wholesale requirements customers and retail customers leave utilities' generation systems through FERC jurisdictional open-access tariffs and obtain their electric power from other energy suppliers. The FERC will permit utilities to seek extra contractual recovery of stranded costs associated with wholesale requirements contracts executed prior to July 11, 1994. The FERC is to be the primary forum for utilities seeking to recover stranded costs arising where retail customers become wholesale transmission customers of a utility. In addition, the FERC will allow utilities to seek to recover stranded costs resulting from retail wheeling, but only in circumstances where a state regulator does not have the authority to address retail stranded costs at the time when retail wheeling is required.

Order No. 889 requires utilities to implement standards of conduct and an Open Access Same-time Information System ("OASIS") to ensure that owners of transmission facilities, including the Company and its affiliates, do not have an unfair competitive advantage in using transmission facilities to market their power. In summary, it requires that utilities completely separate their wholesale power marketing and transmission operations functions. The NOPR on Capacity Reservation Open Access Transmission Tariffs specifies filing requirements to be followed by public utilities in making transmission tariff filings based on capacity reservations for all transmission users. If adopted, the capacity reservation open access tariff would replace the pro forma tariff implemented in Order No. 888.

As required by Order No. 888, the Company filed a compliance transmission tariff on behalf of itself and Cheyenne on July 9, 1996. The Company made various additional filings with the FERC throughout 1996 to meet the requirements of Order Nos. 888 and 889. On January 29, 1997, the FERC issued an order accepting the non-rate terms and conditions contained in the Company's Order No. 888 transmission tariff. The rates set out in that tariff are the same as those proposed by the Company and Cheyenne in an Offer of Settlement submitted in an earlier proceeding and now pending before the FERC for review.

On March 29, 1996, the FERC accepted the request of e prime, a non-regulated subsidiary, for authorization to act as a power marketer, subject to certain conditions. On April 15, 1996, e prime made a required compliance filing, but also submitted a request for rehearing on one of the conditions imposed by the FERC. The FERC accepted the compliance filing, but the request for rehearing is still pending.

Environmental Issues

Environmental Site Cleanup

As described below, the Company has been or is currently involved with the clean-up of contamination from certain hazardous substances. In all situations, the Company is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, the Company intends to pursue recovery from other PRPs. To the extent such costs are not recovered, the Company currently believes it is probable that such costs will be recovered through 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.

Under the CERCLA, the EPA has identified, and a Phase II environmental assessment has revealed, low level, widespread contamination from hazardous substances at the Barter Metals Company ("Barter")properties located in central Denver. For an estimated 30 years, the Company sold scrap metal and electrical equipment to Barter for reprocessing. The Company has completed the cleanup of this site at a cost of approximately $9 million and has received responses from the Colorado Department of Public Health and Environment ("CDPHE") indicating that no further action is required related to these properties. On January 3, 1996, in a lawsuit by the Company against its insurance providers, the Denver District Court entered final judgment in favor of the Company in the amount of $5.6 million for certain cleanup costs at Barter. Several appeals and cross appeals have been filed by one of the insurance providers and the Company in the Colorado Court of Appeals. The insurance provider has posted supersedeas bonds in the amount of $9.7 million ($7.7 million attributable to the Barter judgment). Previously, the Company had received certain insurance settlement proceeds from other insurance providers for Barter and other contaminated sites and a portion of those funds remains to be allocated to this site by the trial court. In addition, the Company expects to recoup additional expenditures beyond insurance proceeds through the sale of the Barter property and from other PRPs. In August 1996, the Company filed a lawsuit against four PRPs seeking recovery of certain Barter related costs.

PCB presence was identified in the basement of an historic office building located in downtown Denver. The Company was negotiating the future cleanup with the current owners; however, on October 5, 1993, the owners filed a civil action against the Company in the Denver District Court. The action alleged that the Company was responsible for the PCB releases and additionally claimed other damages in unspecified amounts. On August 8, 1994, the Denver District Court entered a judgment approving a $5.3 million offer of settlement between the Company and the building

owners resolving all claims. In December 1995, complaints were filed by the Company against all applicable insurance carriers in the Denver District Court. A trial date regarding the insurance carriers has been established for August 1997.

The Ramp Industries disposal facility, located in Denver, Colorado has been designated by the EPA as a Superfund hazardous substance site pursuant to CERCLA. On November 29, 1995, the Company received from the EPA a Notice of Potential Liability and Request for Information related to such site and the Company has responded to this request. The EPA is conducting an investigation of the contamination at this site and is in the process of identifying the nature and quantities of hazardous wastes delivered to, processed and currently stored at the site by PRPs. As of the end of 1996, the EPA has not yet developed a site specific plan for the cleanup or remediation, therefore at this time, the Company cannot estimate the amount, if any, of its potential liability related to this matter. It is anticipated that the EPA will notify the Company with the results of its investigation sometime during 1997.

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

Environmental Matters Related to Air Quality and Pollution Control

Under the Clean Air Act Amendments of 1990, coal burning power plants are required to reduce SO2 and NOx emissions to specified levels through a phased approach. The Company's facilities must comply with the Phase II requirements which will be effective in the year 2000. The Company expects to meet the Phase II emission standards placed on SO2 through the use of low sulfur coal and the operation of pollution control equipment on certain generation facilities. The Company will be required to modify certain boilers by the year 2000 to reduce the NOx emissions in order to comply with Phase II requirements. The estimated Phase II costs for future plant modifications to meet NOx requirements is approximately $13 million. The Company is studying its options to reduce NOx and SO2 emissions and, currently does not anticipate that these regulations will significantly impact its operations.

Hayden Steam Electric Generating Station

On May 21, 1996, the Company and the other joint owners of the Hayden station reached an agreement, as discussed below, with a conservation organization, the CDPHE and the EPA which provides for a complete and final release of all civil claims for violations alleged in complaints filed by the conservation organization, the CDPHE and the EPA against the joint owners. The complaints filed, pursuant to provisions of the Federal Clean Air Act, by a conservation organization and the EPA alleged, among other things, that the station exceeded the 20% opacity limitations during various periods extending from 1988 to mid-1995. In August, 1996 the U.S. District Court for the District of Colorado entered the settlement agreement which effectively resolved this litigation. The Company is the operator and owns an average undivided interest of approximately 53% of the station's two generating units.

In connection with the above settlement, the joint owners of the Hayden station made the following payments in 1996: 1) a $2 million payment to the U.S. Treasury, 2) a contribution of $2 million to a "Land Trust Fund" to be used for the purchase of land and/or conservation easements in the Yampa Valley and 3) a contribution of $250,000 to be used for the conversion of vehicles and/or wood burning appliances to natural gas in the Yampa Valley. The Company's portion of these costs is approximately $2.3 million, which has been expensed in the accompanying financial statements. The joint owners have committed to the installation of emission control equipment on both generating units to reduce future particulate (opacity), SO2 and NOx emissions over the next three years. The joint owners estimate that the cost of installing emission control equipment capable of reducing the emissions to the levels required under the agreement, consisting of fabric filter dust collectors, lime spray dryers and low NOx burners on both units, is approximately $130 million, with the Company's portion totaling approximately $70 million. Also, the settlement includes stipulated future penalties for failure to comply with the terms of the agreement, including specific provisions related to meeting

construction deadlines associated with the installation of additional emission control equipment and complying with particulate, SO2 and NOx emissions limitations.

Craig Steam Electric Generating Station

On October 9, 1996, a conservation organization filed a complaint in the U.S. District Court pursuant to provisions of the Federal Clean Air Act (the "Act") against the joint owners of the Craig Steam Electric Generating Station. Tri-State is the operator of the Craig station and the Company owns an undivided interest (acquired in April 1992) in each of two units at the station totaling approximately 9.7%. The plaintiff alleged that: 1) the station exceeded the 20% opacity limitations in excess of 14,000 six minute intervals during the period extending from the first quarter of 1991 through the second quarter of 1996, and 2) the owners failed to operate the station in a manner consistent with good air pollution control practices. The complaint seeks, among other things, civil monetary penalties and injunctive relief. The Act provides for penalties of up to $25,000 per day per violation, but the level of penalties imposed in any particular instance is discretionary. The Company does not believe that its potential liability or the future impact of this litigation on plant operations will have a material impact on the Company's results of operations, financial position or cash flows.

Valmont Steam Electric Generating Station

On July 1, 1996, the Company received a Notice of Violation ("NOV") from the CDPHE which alleges inadequate reporting of NOx and SO2 information and excess NOx emissions at the Valmont Steam Electric Generating Station for the period January 1, 1995 through August 22, 1995. The Company has responded to the NOV and believes that the amount of penalties, if any, that may result from such alleged violations would not have a material impact on the Company's results of operations, financial position or cash flows.

Purchase Requirements

Coal purchases and transportation

At December 31, 1996, the Company had in place long-term contracts for the purchase of coal through 2017. The minimum remaining quantities to be purchased under these contracts total 78 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 $678 million at December 31, 1996.

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 2000, provide for a minimum remaining transport quantity of 15 million tons. Contract prices for coal transportation are negotiated based on market conditions and are adjusted periodically for inflation and operating factors. Total estimated obligations, based on current prices, were approximately $31 million at December 31, 1996.

Natural gas purchases and transportation

The Company and Cheyenne have entered into long-term contracts for the purchase, firm transportation and storage of natural gas. These contracts, excluding the thirty year contract with Young Storage which has been accounted for as a capital lease, expire on various dates through 2002. During 1996, the Company renegotiated contracts with its primary gas pipeline supplier and committed to continue purchasing firm transportation and gas storage services through 2002. At December 31, 1996, the Company and Cheyenne have minimum obligations under such contracts of approximately $123 million in 1997 declining thereafter for a total estimated commitment of approximately $516 million.

Purchased power

The Company and Cheyenne have entered into agreements with utilities and QFs for purchased power to meet system load and energy requirements, replace generation from Company-owned units under maintenance and during outages, and meet the Company's operating reserve obligation to the Pool.

The Company has various pay-for-performance contracts with QFs having expiration dates through the year 2022. In general, these contracts provide for capacity payments, subject to the QFs meeting certain contract obligations, and energy payments based on actual power taken under the contracts. The capacity and energy costs are recovered through base rates, the ECA/ICA and the QFCCA. Additionally, the Company and Cheyenne have long-term purchased power contracts with various regional utilities expiring through 2018. In general, these contracts provide for capacity and energy payments which approximate the cost of the sellers. Total capacity and energy payments associated with such contracts were $453 million, $445 million, and $427 million in 1996, 1995 and 1994, respectively.

At December 31, 1996, the estimated future payments for capacity that the Company and Cheyenne are obligated to purchase, subject to availability, are as follows:

	QFs	Regional Utilities	Total
	(Thousands of Dollars)		
1997	$ 143,236	$ 180,896	$ 324,132
1998	143,502	184,701	328,203
1999	143,827	175,662	319,489
2000	141,910	164,994	306,904
2001	140,438	143,894	284,332
2002 and thereafter	1,000,001	1,270,872	2,270,873
Total	$1,712,914	$2,121,019	$3,833,933

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

Other purchases

Commitments made for the purchase of materials, plant and equipment additions, DSM expenditures and other various items aggregated approximately $478 million at December 31, 1996.

Employee Litigation

Several employee lawsuits have been filed against the Company involving alleged discrimination and breach of certain fiduciary duties to employees. The Company is actively contesting all such lawsuits and believes that the ultimate outcome will not have a material impact on the Company's results of operations, financial position or cash flow.

On August 13, 1996, eighty-eight former Information Technology and Systems ("IT&S") employees filed a lawsuit against the Company. The complaint, which was subsequently amended to add two other former IT&S employees, alleges that the Company unfairly amended its severance plan in connection with a restructuring in late 1994 to exclude the IT&S function/positions that were outsourced to IBM, effective February 1, 1995. The Company believes that the amended severance plan is lawful and enforceable and believes that the ultimate outcome of the lawsuit will not have a material impact on the Company's results of operations, financial position or cash flows.

On July 19, 1996, a class action complaint was filed by fourteen plaintiffs allegedly on behalf of all non-managerial, non-clerical women in the Company's regional facilities. The complaint asserts that the Company has

engaged in company wide pattern and practice of sexual discrimination, including sexual harassment and retaliation. A previous class complaint filed by some of these plaintiffs along with other named plaintiffs, was withdrawn after the Company filed its response. It is too early to predict the outcome of the class action complaint. The Company intends to actively contest the class action and believes the ultimate outcome of the individual plaintiffs' cases will not have a material impact on the Company's results of operations, financial position or cash flows.

Certain employees terminated as part of the Company's 1991/1992 organizational analysis asserted breach of contract and promissory estoppel with respect to job security and breach of the covenant of good faith and fair dealing. Of the 21 actions filed, the trial court directed verdicts in favor of the Company in 19 cases. A jury entered verdicts adverse to the Company in two cases which were subsequently appealed by the Company. On February 6, 1997, the Colorado Court of Appeals issued a decision on all issues in favor of the Company. The employees can appeal the decision of the Colorado Court of Appeals to the Colorado Supreme Court. The Company believes that the ultimate outcome of the lawsuit will not have a material impact on the Company's results of operations, financial position or cash flow.

Union Contracts

In late December 1995, the Company's contracts with the International Brotherhood of Electrical Workers, Local 111 ("IBEW Local 111") expired. Previously, an arbitrator had rejected the Company's attempt to terminate the contracts on the expiration dates. Therefore, negotiation of limited issues was reopened. The parties were unable to reach agreement on the contract issues reopened through the negotiation process and, as a result, the Company and IBEW Local 111 entered into binding arbitration on March 20, 1996, as required under the contracts. On June 4, 1996, the arbitrator ruled that the Operations, Production and Maintenance ("OP&M") collective bargaining agreement with the Union would continue until May 31, 1997 and that the employees covered by the agreement would receive a wage increase of 3.5% retroactive to December 1995. Such amount had been previously accrued. Subsequent to the arbitrator's decision on the OP&M agreement, the Company and IBEW Local 111 came to an agreement on the Meter Reader, Order Reader and Field Credit Representative contract with a contract term and a wage increase consistent with the OP&M agreement. At December 31, 1996, approximately 2,090 employees, or 45% of the Company's total workforce, are represented by IBEW Local 111.

On June 21, 1996, the National Labor Relations Board ordered the Company to reinstate approximately 150 union employees laid off or moved to other positions in the 1994 restructuring. The Company was ordered to make whole, with interest, any net loss of earnings or other benefits since the layoff. Thirty-two employees were reinstated and, while the final costs associated with the order have not been determined, the Company accrued $2.0 million during 1996 related to this obligation.

In addition, IBEW Local 111 filed several grievances during 1996 relating to the employment of certain non-union personnel to perform services for the Company. A decision has been entered on three of the multiple grievances, with two of those decisions requiring that the Company pay union wage rates on new construction jobs performed by outside vendors. The Company has filed suit seeking to reverse one of these decisions and challenging the subcontracting provision of the labor agreement, all of the outstanding subcontracting grievances and both of the existing adverse decisions as violations of federal law. The Company and the union have entered into negotiations to resolve this dispute over contracting. A decision is expected in March 1997.

Leasing Program

The Company and its subsidiaries lease various equipment and facilities used in the normal course of business, some of which are accounted for as capital leases. Expiration of the capital leases range from 1998 to 2025. The net book value of property under capital leases was $49.2 million and $53.7 million at December 31, 1996, and 1995, respectively. Assets acquired under capital leases are recorded as property at the lower of fair-market value or the present value of future lease payments, and are amortized over their actual contract term in

accordance with practices allowed by the CPUC. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

The majority of the operating leases are under a leasing program that has initial noncancellable terms of one year, while the remaining leases have various terms. These leases may be renewed or replaced. No material restrictions exist in these leasing agreements concerning dividends, additional debt, or further leasing. Rental expense for 1996, 1995 and 1994 was $25.0 million, $23.5 million and $29.7 million, respectively.

Estimated future minimum lease payments at December 31, 1996 are as follows:

	Capital Leases	Operating Leases
	(Thousands of Dollars)	
1997	$ 9,585	$ 20,790
1998	9,392	20,947
1999	7,903	18,019
2000	5,097	16,129
2001	5,035	11,880
All years thereafter	81,177	20,489
Total future minimum lease payments	118,189	$ 108,254
Less amounts representing interest	69,035	
Present value of net minimum lease payments	$ 49,154	

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.

10. Jointly-Owned Electric Utility Plants

The Company's investment in jointly-owned plants and its ownership percentages as of December 31, 1996 is:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of Dollars)		
Hayden Unit 1	$ 38,213	$ 29,860	$ 1,526	75.50
Hayden Unit 2	58,211	32,873	300	37.40
Hayden Common Facilities	2,117	392	3,287	53.10
Craig Units 1 & 2	57,057	23,352	647	9.72
Craig Common Facilities Units 1 & 2	7,714	3,033	958	9.72
Craig Common Facilities Units 1,2 & 3	8,371	3,310	407	6.47
Transmission Facilities, Including Substations	79,166	22,105	95	42.0-73.0
	$ 250,849	$ 114,925	$ 7,220	

These assets include approximately 320 Mw of net dependable generating capacity. The Company is responsible for its proportionate share of operating expenses (reflected in the consolidated statements of income) and construction expenditures.

11. Employee Benefits

Pensions

The Company and Cheyenne maintain a noncontributory defined benefit pension plan covering substantially all employees.

The net pension expense in 1996, 1995 and 1994 was comprised of:

	1996	1995	1994
		(Thousands of Dollars)	
Service cost	$ 14,317	$ 11,659	$ 16,169
Interest cost on projected benefit obligation	46,497	46,570	45,518
Actual return on plan assets	(74,646)	(123,531)	5,844
Amortization of net transition asset	(3,674)	(3,674)	(3,674)
Other items	24,362	75,521	(56,996)
Net pension expense	$ 6,856	$ 6,545	$ 6,861

The pension plan was amended in 1994 (as discussed below) requiring the use of two sets of assumptions in the calculation of the 1994 net periodic pension cost. Significant assumptions used in determining net periodic pension cost were:

	1996	1995	Apr - Dec 1994	Jan - Mar 1994
Discount rate	7.25%	8.75%	8.0%	7.5%
Expected long-term increase in compensation level	4.0%	5.0%	5.0%	5.0%
Expected weighted average long-term rate of return on assets	9.75%	9.75%	10.5%	10.5%

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, 1996 and 1995, 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. The Company and Cheyenne's funding policy is to contribute annually, at a minimum, the amount necessary to satisfy the IRS funding standards.

	1996	1995
	(Thousands of Dollars)	
Actuarial present value of benefit obligations:		
Vested	$ 514,762	$ 523,539
Nonvested	28,689	31,678
	543,451	555,217
Effect of projected future salary increases	85,216	91,810
Projected benefit obligation for service rendered to date	628,667	647,027
Plan assets at fair value	(634,967)	(588,314)
Projected benefit obligation in excess of plan assets	6,300	(58,713)
Unrecognized net loss	1,110	62,092
Prior service cost not yet recognized in net periodic pension cost	27,758	30,063
Unrecognized net transition asset at January 1, 1986, being recognized over 17 years	(22,042)	(25,716)
Prepaid pension asset	$ 13,126	$ 7,726

Significant assumptions used in determining the benefit obligations at the end of each respective year were:

	1996	1995
Discount rate	7.75%	7.25%
Expected long-term increase in compensation level	4.25%	4.0%

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

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

Approximately 550 employees elected to participate in the early retirement/severance enhancement program, of which approximately 370 employees elected the early retirement benefit. The total cost of the program was approximately $39.7 million. These costs were deferred and, effective April 1, 1994, are being amortized to expense over approximately 4.5 years in accordance with rate regulatory treatment. This amortization period represents the participants' average remaining years of service to their expected retirement date.

Involuntary severance program

During 1994, in a continuing effort to lower operating costs, the Company implemented an involuntary severance program which reduced management and staff levels by approximately 550 employees. Approximately $10.7 million of involuntary severance costs were accrued, of which $8.7 million reduced pre-tax earnings.

Postretirement benefits other than pensions

The Company and Cheyenne 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 Cheyenne. Historically, the Company has recorded the cost of these benefits on a pay-as-you-go basis, consistent with the regulatory treatment. Effective January 1, 1993, the Company and Cheyenne adopted SFAS 106 costs based on the level of expense determined in accordance with the CP nd WPSC. SFAS 106 requires the accrual, during the years that an employee renders service to the Company, of the expected cost of providing postretirement benefits other than pensions to the employee and the employee's beneficiaries and covered dependents.

The Company is transitioning to full accrual accounting for OPEB costs between January 1, 1993 and December 31, 1997, consistent with the accounting requirements for rate regulated enterprises. All OPEB costs deferred during the transition period will be amortized on a straight line basis over the subsequent 15 years. Effective December 1, 1993, the Company began recovering such costs as provided in the Fort St. Vrain Supplemental Settlement Agreement. On January 13, 1995, the CPUC approved the 1994 revision to the Supplemental Settlement Agreement, which accelerated the recovery of OPEB costs to comply with SFAS 106 and approved other changes to certain ratemaking principles. The change in recovery was retroactive to January 1, 1994, and accordingly, resulted in an increased OPEB expense for that year and subsequent years.

The Company filed a FERC rate case in December 1995 which included a request for approval to recover all electric wholesale jurisdiction SFAS 106 costs (see Note 9.). Effective January 1, 1993, Cheyenne began recovering SFAS 106 costs as approved by the WPSC. The Company and Cheyenne fund SFAS 106 costs in external trusts based on the amounts reflected in cost-of-service, consistent with the respective rate orders.

The net periodic postretirement benefit cost in 1996, 1995 and 1994 under SFAS 106 was comprised of:

	1996	1995	1994
		(Thousands of Dollars)	
Service cost	$ 6,928	$ 6,027	$ 6,101
Interest cost on projected benefit obligation	22,982	24,761	24,111
Return on plan assets	(4,500)	(2,578)	(938)
Amortization of net transition obligation at January 1, 1993 assuming a 20 year amortization period	12,710	12,710	12,710
Net postretirement benefit cost required by SFAS 106	38,120	40,920	41,984
OPEB expense recognized in accordance with current regulation	(31,271)	(30,893)	(30,266)
Increase in regulatory asset (Note 1)	6,849	10,027	11,718
Regulatory asset at beginning of year	47,600	37,573	25,855
Regulatory asset at end of year	$ 54,449	$ 47,600	$ 37,573

Significant assumptions used in determining net periodic postretirement benefit cost were:

	1996	1995	Apr - Dec 1994	Jan - Mar 1994
Discount rate	7.25%	8.75%	8.0%	7.5%
Expected long-term increase in compensation level	4.0%	5.0%	5.0%	5.0%
Expected weighted average long-term rate of return on assets	9.75%	9.75%	10.5%	10.5%

A comparison of the actuarially computed benefit obligations and plan assets at December 31, 1996 and 1995 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, government securities and other short-term investments held either directly or in commingled funds.

	1996	1995
	(Thousands of Dollars)	
Accumulated postretirement benefit obligation:		
Retirees and eligible beneficiaries	$ 110,692	$ 122,395
Other fully eligible plan participants	81,676	93,161
Other active plan participants	90,559	102,739
Total	282,927	318,295
Plan assets at fair value	(63,744)	(41,129)
Accumulated benefit obligation in excess of plan assets	219,183	277,166
Unrecognized net gain (loss)	39,847	(11,905)
Unrecognized transition obligation	(203,353)	(216,063)
Accrued postretirement benefit obligation	$ 55,677	$ 49,198

Significant assumptions used in determining the accumulated postretirement benefit obligation at the end of each respective year were:

	1996	1995
Discount rate	7.75%	7.25%
Ultimate health care cost trend rate	5.0%	4.5%
Expected long-term increase in compensation level	4.0%	4.0%

The assumed health care cost trend rate for 1997 is 9.0%, decreasing to 4.5% in 2006 in 0.5% annual increments. A 1% increase in the assumed health care cost trend will increase the estimated total accumulated

benefit obligation by $35.1 million, and the service and interest cost components of net periodic postretirement benefit costs by $5.1 million.

Postemployment benefits

The Company and Cheyenne adopted SFAS 112 on January 1, 1994, the effective date of the statement. SFAS 112 establishes the accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (postemployment benefits). At December 31, 1996 and 1995, the Company had recorded a $24.8 million and $23.5 million regulatory asset and a corresponding liability on the consolidated balance sheet, assuming a 7.75% and an 7.25% discount rate, respectively. The Company has historically recorded these costs on a pay-as-you-go basis. The Company filed a FERC rate case in December 1995 and a retail gas rate case in June 1996 which included a request for recovery of all electric wholesale and retail jurisdiction SFAS 112 costs. For discussion regarding the recovery of these costs, see Note 1 and Note 9.

Incentive compensation

The Omnibus Incentive Plan ("OIP") provides for annual and long-term incentive awards for officers and management employees. One million shares of common stock have been authorized for awards under the OIP as it allows for the issuance of restricted shares and/or stock options. The Company recognizes compensation expense for restricted stock awards based on the fair value of the Company's common stock on the date of grant, consistent with SFAS 123. Cash, restricted stock awards (restrictions lapse two years from the grant date) and stock option awards (which vest ratably during a three-year period) were made under the OIP during 1996, 1995 and 1994.

As allowed in SFAS 123, the Company applies APB Opinion No. 25 in accounting for its stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options as the exercise price of the options equals the fair-market value of the Company's common stock at the date of grant. Assuming compensation cost for stock options granted in 1996 and 1995 had been determined consistent with SFAS 123 using the fair-value based method, the Company's reported net income would have been reduced by $0.3 million in 1996 and $0.2 million in 1995 which would not have impacted reported earnings per share for 1996 and 1995. SFAS 123's method of accounting for stock-based compensation plans has not been applied to options granted prior to January 1, 1995 and as a result the pro forma compensation cost may not be representative of that to be expected in future years.

A summary of the Company's stock options at December 31, 1996, 1995 and 1994 and changes during the years then ended is presented in the table below:

	1996		1995		1994	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at beginning of year	347,931	$ 29.33	195,744	$ 28.53	58,544	$ 28.13
Granted	158,270	$ 35.13	161,000	$ 30.29	149,700	$ 28.73
Exercised	(51,673)	$ 30.21	(267)	$ 29.00	-	$ -
Forfeited	(13,301)	$ 32.84	(8,546)	$ 29.17	(12,500)	$ 29.00
Outstanding at end of year	441,227	$ 31.38	347,931	$ 29.33	195,744	$ 28.53
Exercisable at end of year	158,970	$ 29.05	125,931	$ 28.52	19,515	$ 28.13
Weighted-average fair value of options granted		$ 4.31		$ 5.39		

The fair value of each option grant is estimated on the date of grant using the Black-Scholes Option-Pricing Model with the following weighted-average assumptions:

	1996	1995
Expected option life	10 years	10 years
Stock volatility	11.95%	16.11%
Risk-free interest rate	6.21%	7.45%
Dividend yield	5.8%	6.6%

The Employee Incentive Plan ("EIP") provides for cash awards to all employees based on the achievement of corporate goals. Certain performance goals were met in each of the last three years.

The expenses accrued under the OIP and the EIP totaled approximately $7.8 million in 1996, $6.4 million in 1995 and $6.0 million in 1994.

In the event that the Company is subject to a change in control, all stock-based awards, such as options and restricted shares, will vest 100% and all performance awards will be paid out immediately in cash, as if the performance objectives have been obtained through the effective date of the change in control. The Merger, when effective, qualifies as a change in control condition.

12. Financial Instruments

Fair value of financial instruments

The following table presents the carrying amounts and fair values of the Company's and subsidiaries' significant financial instruments at December 31, 1996 and 1995. The carrying amount of all other financial instruments approximates fair value. SFAS 107 defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale.

	1996		1995	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Investments, at cost	$ 30,249	$ 30,416	$ 7,575	$ 7,623
Preferred stock subject to mandatory redemption	42,489	43,685	43,865	45,184
Long-term debt	1,370,423	1,404,972	1,229,231	1,307,128

The fair value of the debt and equity securities included in Investments, at cost, is estimated based on quoted market prices for the same or similar investments. The debt securities are classified as held-to-maturity and the equity securities are classified as available-for-sale. The unrealized holding gains and losses for these debt and equity securities are not significant.

The estimated fair values of preferred stock subject to mandatory redemption and long-term debt are based on quoted market prices of the same or similar instruments. Since the Company and Cheyenne are subject to regulation, any gains or losses related to the difference between the carrying amount and the fair value of these financial instruments would not be realized by the Company's shareholders.

Off-balance-sheet financial instruments

YGSC, a wholly-owned subsidiary of e prime, and the Company have guaranteed 50% of amounts financed under a $32 million Credit Agreement among Young Gas and various lending institutions entered into on

June 27, 1995. This debt financing is for the development, construction and operation of an underground natural gas storage facility in northeastern Colorado.

Concentration of credit risk - accounts receivable

No individual customer or group of customers engaged in similar activities represents a material concentration of credit risk to the Company and its subsidiaries.

13. Income Taxes

The provisions for income taxes for the years ended December 31, 1996, 1995 and 1994 consist of the following:

	1996	1995	1994
		(Thousands of Dollars)	
Current income taxes:			
Federal	$ 41,737	$ 58,728	$ 22,081
State	951	2,807	(2,016)
Total current income taxes	42,688	61,535	20,065
Deferred income taxes:			
Federal	53,612	38,006	31,042
State	7,287	1,164	3,192
Total deferred income taxes	60,899	39,170	34,234
Investment tax credits - net	(7,256)	(5,348)	(5,799)
Total provision for income taxes	$ 96,331	$ 95,357	$ 48,500

During 1994, as a result of a detailed analysis of the income tax accounts, the Company recorded a decrease in its income tax liabilities, which served to reduce Federal and state income tax expenses by approximately $21.3 million, or 34 cents per share. The detailed analysis was completed in conjunction with the Company's implementation of the full normalization method of accounting for income taxes as provided for in a rate order from the CPUC.

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

	1996		1995		1994	
			(Thousand of Dollars)			
Tax computed at U.S. statutory rate on pre-tax accounting income	$ 100,337	35.0%	$ 95,975	35.0%	$ 76,569	35.0%
Increase (decrease) in tax from:						
Allowance for funds used during construction	(1,438)	(0.5)	(2,495)	(0.9)	(2,449)	(1.1)
Amortization of investment tax credits	(7,256)	(2.5)	(5,348)	(1.9)	(5,792)	(2.6)
Cash surrender value of life insurance policies	(11,265)	(3.9)	(9,546)	(3.5)	(7,643)	(3.5)
Amortization of prior flow-through amounts	10,509	3.6	10,509	3.8	10,509	4.8
Tax accrual adjustment	-	-	-	-	(21,262)	(9.7)
Other-net	5,444	1.9	6,262	2.3	(1,432)	(0.7)
Total income taxes	$ 96,331	33.6%	$ 95,357	34.8%	$ 48,500	22.2%

The Company and its regulated subsidiaries have historically provided for deferred income taxes to the extent allowed by their regulatory agencies whereby deferred taxes were not provided on all differences between financial statement and taxable income (the flow-through method). To give effect to temporary differences for which deferred taxes were not previously required to be provided, a regulatory asset was recognized. The regulatory asset represents temporary differences primarily associated with prior flow-through amounts and the equity component of allowance for funds used during construction, net of temporary differences related to

unamortized investment tax credits and excess deferred income taxes that have resulted from historical reductions in tax rates (see Note 1).

The tax effects of significant temporary differences representing deferred tax liabilities and assets as of December 31, 1996 and 1995 are as follows:

	1996	1995
	(Thousands of Dollars)	
Deferred income tax liabilities:		
Accelerated depreciation and amortization	$ 412,047	$ 376,468
Plant basis differences (prior flow-through)	132,149	152,631
Allowance for equity funds used during construction	48,952	50,411
Pensions	38,790	36,583
Other	68,940	50,760
Total	700,878	666,853
Deferred income tax assets:		
Investment tax credits	65,278	69,751
Contributions in aid of construction	63,317	55,654
Other	28,641	52,534
Total	157,236	177,939
Net deferred income tax liability	$ 543,642	$ 488,914

As of December 31, 1996, the Company has cumulative AMT carryforwards of approximately $3.8 million and state tax credit carryforwards of approximately $1.6 million. A valuation allowance has not been recorded as the Company expects that all deferred income tax assets will be realized in the future.

14. Segments of Business

1996	Electric	Gas	Other	Total
		(Thousands of Dollars)		
Operating revenues	$ 1,488,990	$ 640,497	$ 41,899	$ 2,171,386
Operating expenses, excluding depreciation and income taxes	1,006,904	549,223	5,813	1,561,940
Depreciation and amortization	116,801	35,735	2,095	154,631
Total operating expenses*	1,123,705	584,958	7,908	1,716,571
Operating income*	365,285	55,539	33,991	454,815
Plant construction expenditures**	223,395	96,842	925	321,162
Identifiable assets:				
Property, plant and equipment**	2,733,699	805,372	59,824	3,598,895
Materials and supplies	41,418	7,325	229	48,972
Fuel inventory	24,594	-	145	24,739
Gas in underground storage	-	42,826	-	42,826
Other corporate assets				857,216
				$ 4,572,648

1995	Electric	Gas	Other	Total
Operating revenues	$ 1,449,096	$ 624,585	$ 36,920	$ 2,110,601
Operating expenses, excluding depreciation and income taxes	1,002,381	538,620	7,046	1,548,047
Depreciation and amortization	109,498	29,901	1,981	141,380
Total operating expenses*	1,111,879	568,521	9,027	1,689,427
Operating income*	337,217	56,064	27,893	421,174
Plant construction expenditures**	198,341	86,482	693	285,516
Identifiable assets:				
Property, plant and equipment**	2,645,045	777,420	58,247	3,480,712
Materials and supplies	47,636	8,886	3	56,525
Fuel inventory	35,509	-	145	35,654
Gas in underground storage	-	44,900	-	44,900
Other corporate assets				733,998
				$ 4,351,789

1994	Electric	Gas	Other	Total
Operating revenues	$ 1,399,836	$ 624,922	$ 32,626	$ 2,057,384
Operating expenses, excluding depreciation and income taxes (1)	1,032,396	558,929	7,732	1,599,057
Depreciation and amortization	107,769	29,078	2,188	139,035
Total operating expenses*	1,140,165	588,007	9,920	1,738,092
Operating income*	259,671	36,915	22,706	319,292
Plant construction expenditures**	223,773	91,492	1,873	317,138
Identifiable assets:				
Property, plant and equipment**	2,543,267	674,974	73,161	3,291,402
Materials and supplies	55,756	11,782	62	67,600
Fuel inventory	31,225	-	145	31,370
Gas in underground storage	-	42,355	-	42,355
Other corporate assets				775,105
				$ 4,207,832

(1) Includes additional expense of approximately $43.4 million for defueling and decommissioning.

* Before income taxes.

** Includes allocation of common utility property.

15. Quarterly Financial Data (Unaudited)

The following summarized quarterly information for 1996 and 1995 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.

	Three Months ended			
	March 31	June 30	September 30	December 31
	(In thousands-except per share data)			
1996				
Operating revenues	$ 622,917	$ 484,787	$ 476,861	$ 586,821
Operating income (1)	$ 104,846	$ 73,286	$ 88,222	$ 92,130
Net income	$ 64,429	$ 34,537	$ 39,256	$ 52,124
Earnings available for common stock	$ 61,457	$ 31,566	$ 36,294	$ 49,181
Weighted average common shares outstanding	63,679	63,998	64,324	64,748
Earnings per weighted average common share	$0.97	$0.49	$0.56	$0.76
1995				
Operating revenues	$ 620,596	$ 498,699	$ 468,453	$ 522,853
Operating income (1)	$ 91,689	$ 62,736	$ 82,736	$ 88,656
Net income	$ 53,644	$ 28,255	$ 45,819	$ 51,138
Earnings available for common stock	$ 50,643	$ 25,255	$ 42,828	$ 48,167
Weighted average common shares outstanding	62,513	62,846	63,077	63,291
Earnings per weighted average common share	$0.81	$0.40	$0.68	$0.76

(1) Operating income amounts have been restated to reflect the reclassification of Merger expenses from operating expenses to miscellaneous income and deductions in accordance with FERC guidance received during the third quarter of 1996.

SCHEDULE II

PUBLIC SERVICE COMPANY OF COLORADO AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years Ended December 31, 1996, 1995 and 1994

	Balance at beginning of period	Additions: Charged to income	Additions: Charged to other accounts(1)	Deductions from reserves(2)	Balance at end of year
	(Thousands of Dollars)				
Reserve deducted from related assets:					
Provision for uncollectible accounts:					
1996	$ 3,630	$ 6,741	$ 477	$ 6,799	$ 4,049
1995	$ 3,173	$ 7,815	$ 4	$ 7,362	$ 3,630
1994	$ 3,276	$ 8,533	$ 132	$ 8,768	$ 3,173

(1) Uncollectible accounts subsequently recovered, transfers from customers' deposit, etc.
(2) Uncollectible accounts written off.

EXHIBIT 12(a)

PUBLIC SERVICE COMPANY OF COLORADO AND SUBSIDIARIES

COMPUTATION OF RATIO OF CONSOLIDATED EARNINGS TO CONSOLIDATED FIXED CHARGES

(not covered by Report of Independent Public Accountants)

	Year Ended December 31,				
	1996	1995	1994	1993	1992
	(Thousands of Dollars, except ratios)				
Fixed charges:					
Interest on long-term debt	$ 92,205	$ 85,832	$ 89,005	$ 98,089	$ 92,581
Interest on borrowings against COLI contracts	40,160	34,717	29,786	25,333	18,312
Other interest	17,238	23,392	14,235	9,445	12,357
Amortization of debt discount and expense less premium	3,621	3,278	3,126	2,018	1,790
Interest component of rental expense	10,649	6,729	6,888	6,824	7,904
Total	$ 163,873	$ 153,948	$ 143,040	$ 141,709	$132,944
Earnings (before fixed charges and taxes on income):					
Net income	$ 190,346	178,856	$ 170,269	$ 157,360	$136,623
Fixed charges as above	163,873	153,948	143,040	141,709	132,944
Provisions for Federal and state taxes on income, net of investment tax credit amortization	96,331	95,357	48,500	60,994	53,149
Total	$ 450,550	428,161	$ 361,809	$ 360,063	$322,716
Ratio of earnings to fixed charges	2.75	2.78	2.53	2.54	2.43

EXHIBIT 12(b)

PUBLIC SERVICE COMPANY OF COLORADO
AND SUBSIDIARIES

COMPUTATION OF RATIO OF CONSOLIDATED EARNINGS TO CONSOLIDATED COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

(not covered by Report of Independent Public Accountants)

	Year Ended December 31,				
	1996	1995	1994	1993	1992
	(Thousands of Dollars, except ratios)				
Fixed charges and preferred stock dividends:					
Interest on long-term debt	$ 92,205	$ 85,832	$ 89,005	$ 98,089	$ 92,581
Interest on borrowings against COLI contracts	40,160	34,717	29,786	25,333	18,312
Other interest	17,238	23,392	14,235	9,445	12,357
Amortization of debt discount and expense less premium	3,621	3,278	3,126	2,018	1,790
Interest component of rental expense	10,649	6,729	6,888	6,824	7,904
Preferred stock dividend requirement	11,848	11,963	12,014	12,031	12,077
Additional preferred stock dividend requirement	5,995	6,377	3,422	4,662	4,699
Total	$ 181,716	$ 172,288	$ 158,476	$ 158,402	$149,720
Earnings (before fixed charges and taxes on income):					
Net income	$ 190,346	$ 178,856	$ 170,269	$ 157,360	$136,623
Interest on long-term debt	92,205	85,832	89,005	98,089	92,581
Interest on borrowings against COLI contracts	40,160	34,717	29,786	25,333	18,312
Other interest	17,238	23,392	14,235	9,445	12,357
Amortization of debt discount and expense less premium	3,621	3,278	3,126	2,018	1,790
Interest component of rental expense	10,649	6,729	6,888	6,824	7,904
Provisions for Federal and state taxes on income, net of investment tax credit amortization	96,331	95,357	48,500	60,994	53,149
Total	$ 450,550	$ 428,161	$ 361,809	$ 360,063	$322,716
Ratio of earnings to fixed charges and preferred stock dividends	2.48	2.49	2.28	2.27	2.16

NCE UNAUDITED PRO FORMA INFORMATION

The following unaudited pro forma combined balance sheet at December 31, 1996 gives effect to the Merger as if it had occurred at December 31, 1996. The unaudited pro forma combined statements of income for each of the three years ended December 31, 1996 give effect to the Merger as if it had occurred on January 1, 1994. These statements are prepared on the basis of accounting as required under a pooling of interests and do not reflect any cost savings or other synergies anticipated by management as a result of the Merger. Accordingly, the pro forma information is not necessarily indicative of the financial position or results of operations that would have occurred had the Merger been consummated for the periods for which it is given effect, nor is it necessarily indicative of future operating results or financial condition.

NEW CENTURY ENERGIES, INC.
UNAUDITED PRO FORMA COMBINED BALANCE SHEET
(Thousands of Dollars)
December 31, 1996

ASSETS

	PSCo	SPS	Pro Forma
Property, plant and equipment, at cost:			
Electric	$ 3,931,413	$ 2,517,580	$ 6,448,993
Gas	1,035,394	-	1,035,394
Steam	17,476	-	17,476
Other	60,749	37,541	98,290
Common to all departments	418,262	-	418,262
Construction in progress	181,597	79,346	260,943
	5,644,891	2,634,467	8,279,358
Less: accumulated depreciation	2,045,996	944,279	2,990,275
Total property, plant and equipment	3,598,895	1,690,188	5,289,083
Investments, at cost, and receivables	46,550	34,446	80,996
Current assets:			
Cash and temporary cash investments	9,406	40,609	50,015
Accounts receivable - net	218,132	67,780	285,912
Accrued unbilled revenues	85,894	20,304	106,198
Recoverable purchased gas and electric energy costs	31,288	15,715	47,003
Materials and supplies, at average cost	48,972	17,776	66,748
Fuel inventory, at average cost	24,739	2,320	27,059
Gas in underground storage, at cost (LIFO)	42,826	-	42,826
Regulatory assets recoverable within one year	44,110	-	44,110
Prepaid expenses and other	41,790	7,469	49,259
Total current assets	547,157	171,973	719,130
Deferred charges:			
Regulatory assets	304,456	107,834	412,290
Unamortized debt expense	10,975	9,864	20,839
Other	64,615	30,489	95,104
Total deferred charges	380,046	148,187	528,233
	$ 4,572,648	$ 2,044,794	$ 6,617,442

The accompanying notes to unaudited pro forma combined balance sheet and statements of income are an integral part of this statement.

NEW CENTURY ENERGIES, INC.
UNAUDITED PRO FORMA COMBINED BALANCE SHEET
(Thousands of Dollars)
December 31, 1996

CAPITAL AND LIABILITIES

	PSCo	SPS	Pro Forma
Common stock (2)	$ 324,094	$ 40,918	$ 103,691
Paid in capital (2)	724,353	307,484	1,293,158
Retained earnings (5)	389,841	383,350	764,646
Total common equity	1,438,288	731,752	2,161,495
Preferred stock:			
Not subject to mandatory redemption	140,008	-	140,008
Subject to mandatory redemption at par	39,913	-	39,913
Long-term debt	1,259,528	720,400	1,979,928
	2,877,737	1,452,152	4,321,344
Noncurrent liabilities:			
Employees' postretirement benefits other than pensions	55,677	2,967	58,644
Employees' postemployment benefits	25,182	2,369	27,551
Total noncurrent liabilities	80,859	5,336	86,195
Current liabilities:			
Notes payable and commercial paper	244,725	53,836	298,561
Long-term debt due within one year	155,030	15,231	170,261
Preferred stock subject to mandatory redemption within one year	2,576	-	2,576
Accounts payable	254,256	63,004	317,260
Dividends payable	36,973	-	36,973
Customers' deposits	21,441	5,842	27,283
Accrued taxes	58,990	19,999	78,989
Accrued interest	33,797	13,151	46,948
Current portion of defueling and decommissioning liability	8,665	-	8,665
Current portion of accumulated deferred income taxes	4,560	3,583	8,143
Merger costs (5)	-	-	8,545
Other	69,203	28,503	97,706
Total current liabilities	890,216	203,149	1,101,910
Deferred credits:			
Customers' advances for construction	50,269	366	50,635
Unamortized investment tax credits	105,928	5,719	111,647
Accumulated deferred income taxes	539,082	367,272	906,354
Other	28,557	10,800	39,357
Total deferred credits	723,836	384,157	1,107,993
	$ 4,572,648	$ 2,044,794	$ 6,617,442

The accompanying notes to unaudited pro forma combined balance sheet and statements of income are an integral part of this statement.

NEW CENTURY ENERGIES, INC.
UNAUDITED PRO FORMA COMBINED STATEMENTS OF INCOME
(Thousands of Dollars, Except per Share Data)
Year ended December 31, 1996

	PSCo	SPS	Pro Forma
Operating revenues:			
Electric	$ 1,488,990	$ 927,549	$ 2,416,539
Gas	640,497	-	640,497
Other	41,899	-	41,899
	2,171,386	927,549	3,098,935
Operating expenses:			
Fuel used in generation	195,442	439,838	635,280
Purchased power	490,428	20,154	510,582
Gas purchased for resale	393,163	-	393,163
Other operating expenses	336,100	113,123	449,223
Maintenance	63,908	34,376	98,284
Depreciation and amortization	154,631	65,864	220,495
Taxes (other than income taxes)	82,899	45,306	128,205
Income taxes	96,331	57,322	153,653
	1,812,902	775,983	2,588,885
Operating income	358,484	151,566	510,050
Other income and deductions:			
Allowance for equity funds used during construction	757	179	936
Miscellaneous income and deductions - net	(19,015)	(5,018)	(24,033)
	(18,258)	(4,839)	(23,097)
Interest charges:			
Interest on long-term debt	92,205	46,096	138,301
Amortization of debt discount and expense less premium	3,621	2,145	5,766
Other interest	57,398	5,597	62,995
Allowance for borrowed funds used during construction	(3,344)	(2,601)	(5,945)
Dividend requirements on preferred stock of subsidiaries	-	1,526	13,495
	149,880	52,763	214,612
Net income	190,346	93,964	272,341
Dividend requirements on preferred stock	11,848	121	-
Earnings available for common stock	$ 178,498	$ 93,843	$ 272,341
Weighted average common shares outstanding (2)	64,187	40,918	103,059
Earnings per weighted average share of common stock outstanding	$2.78	$2.29	$2.64

The accompanying notes to unaudited pro forma combined balance sheet and statements of income are an integral part of this statement.

NEW CENTURY ENERGIES, INC.
UNAUDITED PRO FORMA COMBINED STATEMENTS OF INCOME
(Thousands of Dollars, Except per Share Data)
Year ended December 31, 1995

	PSCo	SPS	Pro Forma
Operating revenues:			
Electric	$ 1,449,096	$ 852,510	$ 2,301,606
Gas	624,585	-	624,585
Other	36,920	-	36,920
	2,110,601	852,510	2,963,111
Operating expenses:			
Fuel used in generation	181,995	376,544	558,539
Purchased power	481,958	6,485	488,443
Gas purchased for resale	392,680	-	392,680
Other operating expenses(3)	346,025	108,411	454,436
Maintenance	64,069	27,594	91,663
Depreciation and amortization	141,380	62,552	203,932
Taxes (other than income taxes)	81,319	43,316	124,635
Income taxes	95,357	69,840	165,197
	1,784,783	694,742	2,479,525
Operating income	325,818	157,768	483,586
Other income and deductions:			
Allowance for equity funds used during construction	3,782	245	4,027
Miscellaneous income and deductions - net (3)	(6,838)	8,141	1,303
	(3,056)	8,386	5,330
Interest charges:			
Interest on long-term debt	85,832	42,421	128,253
Amortization of debt discount and expense less premium	3,278	2,048	5,326
Other interest	58,109	1,695	59,804
Allowance for borrowed funds used during construction	(3,313)	(2,744)	(6,057)
Dividend requirements on preferred stock of subsidiaries	-	-	17,588
	143,906	43,420	204,914
Net income	178,856	122,734	284,002
Dividend requirements on preferred stock	11,963	5,625	-
Earnings available for common stock	$ 166,893	$ 117,109	$ 284,002
Weighted average common shares outstanding (2)	62,932	40,918	101,804
Earnings per weighted average share of common stock outstanding	$2.65	$2.86	$2.79

The accompanying notes to unaudited pro forma combined balance sheet and statements of income are an integral part of this statement.

NEW CENTURY ENERGIES, INC.
UNAUDITED PRO FORMA COMBINED STATEMENTS OF INCOME
(Thousands of Dollars, Except per Share Data)
Year ended December 31, 1994

	PSCo	SPS	Pro Forma
Operating revenues:			
Electric	$ 1,399,836	$ 824,008	$ 2,223,844
Gas	624,922	-	624,922
Other	32,626	-	32,626
	2,057,384	824,008	2,881,392
Operating expenses:			
Fuel used in generation	198,118	386,796	584,914
Purchased power	437,087	4,401	441,488
Gas purchased for resale	397,877	-	397,877
Other operating expenses	369,094	107,130	476,224
Maintenance	67,097	30,245	97,342
Defueling and decommissioning	43,376	-	43,376
Depreciation and amortization	139,035	59,759	198,794
Taxes (other than income taxes)	86,408	42,510	128,918
Income taxes	48,500	57,126	105,626
	1,786,592	687,967	2,474,559
Operating income	270,792	136,041	406,833
Other income and deductions:			
Allowance for equity funds used during construction	3,140	179	3,319
Gain on sale of WestGas Gathering, Inc.	34,485	-	34,485
Miscellaneous income and deductions - net	(6,014)	1,867	(4,147)
	31,611	2,046	33,657
Interest charges:			
Interest on long-term debt	89,005	37,710	126,715
Amortization of debt discount and expense less premium	3,126	2,020	5,146
Other interest	44,021	2,028	46,049
Allowance for borrowed funds used during construction	(4,018)	(1,303)	(5,321)
Dividend requirements on preferred stock of subsidiaries	-	-	16,892
	132,134	40,455	189,481
Net income	170,269	97,632	251,009
Dividend requirements on preferred stock	12,014	4,678	-
Earnings available for common stock	$ 158,255	$ 92,754	$ 251,009
Weighted average common shares outstanding (2)	61,547	40,918	100,419
Earnings per weighted average share of common stock outstanding	$2.57	$2.27	$2.50

The accompanying notes to unaudited pro forma combined balance sheet and statements of income are an integral part of this statement.

NEW CENTURY ENERGIES, INC.

Notes to Unaudited Pro Forma Combined Balance Sheet and Statements of Income
December 31, 1996

(1) The unaudited pro forma combined statements of income have been prepared from the historical consolidated financial statements of PSCo and SPS and are presented as if the companies were combined during all periods presented herein.

(2) The unaudited pro forma combined balance sheet and statements of income reflect the conversion of each outstanding share of PSCo Common Stock into one share of NCE Common Stock, and each outstanding share of SPS Common Stock into 0.95 of one share of NCE Common Stock in accordance with the terms of the Merger.

(3) There were no intercompany transactions and, accordingly, no pro forma elimination adjustments were made. Certain amounts have been reclassified in order to provide consistent presentation.

(4) For a discussion regarding material commitments and contingencies relating to PSCo, see Note 9. Commitments and Contingencies in Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA. For SPS, reference is made to its 1996 Annual Report on Form 10-K and its Form 10-Q for the quarter ended November 30, 1996.

(5) The unaudited pro forma combined financial statements include nonrecurring charges directly related to the Merger totaling \$9.4 million and \$6.8 million for the years ended December 31, 1996 and 1995, respectively. These nonrecurring charges include merger transaction costs and benefits expense resulting from an accelerated vesting of certain benefits. The unaudited pro forma combined statements of income do not reflect future nonrecurring charges directly related to the Merger, estimated to total approximately \$8.5 million. The pro forma combined balance sheet at December 31, 1996 has been adjusted to include these items with the recognition of additional current liabilities and the reduction of retained earnings.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Does not apply.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

Biographies concerning the directors of the registrant are contained under ELECTION OF DIRECTORS in the registrant's 1997 Proxy Statement, which is incorporated herein by reference. The following table sets forth certain information concerning the directors and executive officers of the Company as of December 31, 1996.

Name	Age	Occupation/Title	Initial Date as Director
D.D. Hock (b)	61	Chairman of the Board	1985
Wayne H. Brunetti	54	President and CEO	1994
Collis P. Chandler, Jr. (g)	70	Chairman, Chandler & Associates, Inc., Chandler-Simpson, Inc. and Chandler Drilling Corp.	1985
Doris M. Drury, Ph.D. (a)(h)	70	John J. Sullivan Professor of Free Enterprise Economics at Regis University, and President of the Center for Business and Economic Forecasting, Inc.	1975
Thomas T. Farley (c)	62	President, Petersen & Fonda, P.C.	1983
Gayle L. Greer (c)	55	Vice President, Time Warner Cable	1986
A. Barry Hirschfeld (e)	54	President, A.B. Hirschfeld Press, Inc.	1988
George B. McKinley (a)(g)	69	Chairman and CEO, First National Banks of Evanston and Kemmerer, Wyoming and President & CEO, First McKinley Corporation	1976
Will F. Nicholson, Jr. (a)(g)	67	Chairman, Rocky Mountain Bank Card System	1981
J. Michael Powers (d)	54	President, Powers Products Co. and Powers Masonry Supply	1978
Thomas E. Rodriguez (c)	52	President and General Manager, Thomas E. Rodriguez & Associates, P.C.	1986
Rodney E. Slifer (e)	62	Partner, Slifer, Smith & Frampton/Vail Associates Real Estate	1988
W. Thomas Stephens (f)(g)	54	Retired Chairman, Manville Corporation	1989
Robert G. Tointon (a)(g)	63	President and CEO Phelps-Tointon, Inc.	1988

(a) Member of Executive Committee.
(b) Chairperson of Executive Committee.
(c) Member of Audit Committee.

(d) Chairperson of Audit Committee.
(e) Member of Pension Investment Committee.
(f) Chairperson of Pension Investment Committee.
(g) Member of Compensation Committee.
(h) Chairperson of Compensation Committee.

Executive Officers	Initial Effective Date
D. D. Hock, Age 61	
Chairman of the Board	February 28, 1989
Chairman of the Board, Cheyenne Light, Fuel and Power Company	September 21, 1988
Chairman of the Board, Fuel Resources Development Co.	March 22, 1989
Chairman of the Board, 1480 Welton, Inc.	September 26, 1988
Chairman of the Board, PSR Investments, Inc.	March 22, 1990
Chairman of the Board, PS Colorado Credit Corporation	March 22, 1990
Chairman of the Board, Green and Clear Lakes Company	December 6, 1988
Chairman of the Board, WestGas InterState, Inc.	April 22, 1993
Chairman of the Board, Natural Fuels Corporation	June 11, 1993
Chairman of the Board, e prime, inc.	January 30, 1995
Chairman of the Board, Young Gas Storage Company	June 27, 1995
Company Service: September, 1962	
Wayne H. Brunetti, Age 54	
President	June 28, 1994
and Chief Executive Officer	January 1, 1996
President, 1480 Welton, Inc.	March 29, 1996
President, PSR Investments, Inc.	March 29, 1996
President, PS Colorado Credit Corporation	March 29, 1996
President, WestGas InterState, Inc.	April 19, 1995
President, Fuel Resources Development Co.	April 27, 1995
President, Natural Fuels Corporation	April 25, 1996
President, Green and Clear Lakes Company	December 5, 1995
Company Service: June, 1994	
Richard C. Kelly, Age 50	
Senior Vice President, Finance, Treasurer	June 28, 1994
and Chief Financial Officer	January 23, 1990
President and Treasurer, New Century Energies, Inc.	August 21, 1995
Vice President, Fuel Resources Development Co.	April 26, 1990
Treasurer, Fuel Resources Development Co.	August 5, 1994
Vice President, PSR Investments, Inc.	September 22, 1986
Vice President, PS Colorado Credit Corporation	March 30, 1987
Treasurer, Cheyenne Light, Fuel and Power Company	July 15, 1994
Treasurer, 1480 Welton, Inc.	July 15, 1994
Treasurer, Green and Clear Lakes Company	July 15, 1994
Treasurer, WestGas InterState, Inc.	July 15, 1994
Vice President and Treasurer, e prime inc.	January 30, 1995
Vice President and Treasurer, Young Gas Storage Company	June 27, 1995
Company Service: May, 1968	

Patricia T. Smith, Age 49	
Senior Vice President and General Counsel	December 5, 1994
Company Service: December, 1994	
W. Wayne Brown, Age 46	
Controller	November 24, 1987
Corporate Secretary	November 23, 1993
Secretary, Cheyenne Light, Fuel and Power Company	December 15, 1993
Secretary, 1480 Welton, Inc.	December 16, 1993
Secretary, PSR Investments, Inc.	December 16, 1993
Secretary, PS Colorado Credit Corporation	December 16, 1993
Secretary, Green and Clear Lakes Company	December 7, 1993
Secretary, Fuel Resources Development Co.	January 27, 1994
Secretary, WestGas InterState, Inc.	May 2, 1994
Secretary, e prime, inc.	January 30, 1995
Secretary, Young Gas Storage Company	June 27, 1995
Company Service: June, 1972	
A. Clegg Crawford, Age 64 *	
Vice President, Engineering and Operations Support	June 28, 1994
Company Service: May, 1989	
Ross C. King, Age 55	
Vice President, Gas and Electric Distribution	June 28, 1994
President, Cheyenne Light, Fuel and Power Company	July 15, 1994
Company Service: February, 1966	
Earl E. McLaughlin, Jr., Age 56	
Vice President, Retail Energy Services	June 28, 1994
Vice President, Cheyenne Light, Fuel and Power Company	March 24, 1994
Company Service: August, 1960	
Ralph Sargent III, Age 47	
Vice President, Production and System Operations	June 28, 1994
Company Service: July, 1978	
Marilyn E. Taylor, Age 54	
Vice President, Human Resources	June 28, 1994
Company Service: December, 1987	

* On February 7, 1997, Mr. Crawford retired from the Company.

Each of the above executive officers, except Mr. Brunetti and Ms. Smith, has been employed by the Company and/or its subsidiaries for more than five years in executive or management positions. Prior to election to the positions shown above and since January 1, 1991:

Mr. Hock has been Chief Operating Officer and President;

Mr. Brunetti has been Chief Operating Officer of the Company and President and Chief Executive Officer of Management Systems International from June 1991 through July 1994 and Executive Vice President of Florida Power & Light Company from 1987 through May 1991;

Mr. Kelly has been Vice President, Financial Services, Principal Accounting Officer and Senior Vice President, Finance and Administration;

Ms. Smith has been Vice President and General Counsel for South Carolina Electric and Gas Company from May 1992 through December 1994 and Vice President, Regulatory Affairs and Purchasing from 1988 through May 1992;

Mr. Crawford has been Vice President, Nuclear Operations and Vice President, Electric Production;

Mr. King has been Manager, Denver Metro Region; Vice President, Regional Customer Operations and Vice President, Metropolitan Customer Operations;

Mr. McLaughlin has been Vice President, Marketing, Customer Services and Support Services;

Mr. Sargent has been Executive Assistant to Chairman, President and Chief Executive Officer and Vice President, Finance, Planning and Communications and Treasurer;

Ms. Taylor has been Vice President, Human Resources and Vice President Administrative Services.

There are no family relationships between executive officers or directors of the Company. There are no arrangements or understandings between the executive officers individually and any other person with reference to their being selected as officers. All executive officers are elected annually by the Board of Directors.

Information concerning the directors of the registrant is contained under ELECTION OF DIRECTORS in the registrant's 1997 Proxy Statement, which information is incorporated herein by reference.

Item 11. ***Executive Compensation***

Information concerning executive compensation is contained under COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS in the registrant's 1997 Proxy Statement, which information is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management***

Information concerning the security ownership of the directors and officers of the registrant is contained under ELECTION OF DIRECTORS in the registrant's 1997 Proxy Statement, which information is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions***

Information concerning relationships and related transactions of the directors and officers of the registrant is contained under CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS in the registrant's 1997 Proxy Statement, which information is incorporated herein by reference.

PART IV

Item 14. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) Financial Statements, Financial Statement Schedules, and Exhibits.

All other schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

Financial statements of several unconsolidated majority-owned subsidiaries are omitted since such subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

3. Exhibits:

The Exhibits include the management contracts and compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 (10) (iii) of Regulation S-K.

(b) Reports on Form 8-K:

A report on Form 8-K, dated January 18, 1996, was filed on January 29, 1996. The item reported was Item 5 - Other Events, which presented updated information related to litigation, a notice of violation issued by the EPA and environmental matters associated with the operations of the Hayden Steam Electric Generating Station.

A report on Form 8-K, dated January 31, 1996, was filed on February 1, 1996. The item reported was Item 5 - Other Events, which reported that on January 31, 1996, at separate meetings of shareholders, the holders of Company Common Stock, Company Preferred Stock, and SPS Common Stock approved the Merger Agreement.

A report on Form 8-K, dated May 21, 1996, was filed on May 22, 1996. The item reported was Item 5 - Other Events, which presented updated information on the settlement of environmental matters associated with the operations of the Hayden Steam Electric Generating Station.

A report on Form 8-K, was dated and filed on February 24, 1997. The item reported was Item 5 - Other Events, which presented information on the Proposed Acquisition of Yorkshire Electricity by the Company and AEP.

EXPERTS

The consolidated balance sheets of the Company and its subsidiaries as of December 31, 1996 and 1995, the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 1996, and the related financial statement schedule, appearing in this Annual Report on Form 10-K, have been audited by Arthur Andersen LLP, independent public accountants, and the selected financial data for each of the five years in the period ended December 31, 1996, appearing in Item 6 of this Annual Report on Form 10-K, other than the ratios and percentages therein, have been derived from the consolidated financial statements audited by Arthur Andersen LLP, as set forth in their report appearing elsewhere herein. The consolidated financial statements, the related financial statement schedule and the selected financial data appearing in Item 6, other than the ratios and percentages therein, which are included in this Annual Report on Form 10-K, are included herein in reliance upon the authority of said firm as experts in accounting and auditing in giving said report.

EXHIBIT 23

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our report included in this Form 10-K, into the Company's previously filed Registration Statement (Form S-3, File No. 33-62233) pertaining to the Automatic Dividend Reinvestment and Common Stock Purchase Plan; the Company's Registration Statement (Form S-3, File No. 33-37431), as amended on December 4, 1990, pertaining to the shelf registration of the Company's First Mortgage Bonds; the Company's Registration Statement (Form S-8, File No. 33-55432) pertaining to the Omnibus Incentive Plan; the Company's Registration Statement (Form S-3, File No. 33-51167) pertaining to the shelf registration of the Company's First Collateral Trust Bonds; the Company's Registration Statement (Form S-3, File No. 33-54877) pertaining to the shelf registration of the Company's First Collateral Trust Bonds and Cumulative Preferred Stock; and the Company's Registration Statement (Form S-3, File No. 333-14727) pertaining to the shelf-registration of the Company's First Collateral Trust Bonds (being one or more series of secured medium-term notes) and to all references to our Firm included in this Form 10-K.

ARTHUR ANDERSEN LLP

Denver, Colorado
February 24, 1997

EXHIBIT 24

POWER OF ATTORNEY

Each director and/or officer of Public Service Company of Colorado whose signature appears herein hereby appoints W. H. Brunetti and R. C. Kelly, and each of them severally, as his or her attorney-in-fact to sign in his or her name and behalf, in any and all capacities stated herein, and to file with the Securities and Exchange Commission, any and all amendments to this Annual Report on Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Public Service Company of Colorado has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 25th day of February, 1997.

PUBLIC SERVICE COMPANY OF COLORADO

By /s/R. C. Kelly

R. C. KELLY
Senior Vice President,
Finance, Treasurer and
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Public Service Company of Colorado and in the capacities and on the date indicated.

Signature	Title	Date
/s/W. H. Brunetti W. H. Brunetti *President and Chief Executive Officer*	Principal Executive Officer and Director	February 25, 1997
/s/R. C. Kelly R. C. Kelly *Senior Vice President, Finance, Treasurer and Chief Financial Officer*	Principal Financial Officer	February 25, 1997
/s/W. Wayne Brown W. Wayne Brown *Controller and Corporate Secretary*	Principal Accounting Office.	February 25, 1997

Signature	Title	Date
/s/D. D. Hock D. D. Hock	Chairman of the Board and Director	February 25, 1997
/s/Collis P. Chandler Collis P. Chandler	Director	February 25, 1997
/s/Doris M. Drury Doris M. Drury	Director	February 25, 1997
/s/Thomas T. Farley Thomas T. Farley	Director	February 25, 1997
/s/Gayle L. Greer Gayle L. Greer	Director	February 25, 1997
/s/A. Barry Hirschfeld A. Barry Hirschfeld	Director	February 25, 1997
/s/George B. McKinley George B. McKinley	Director	February 25, 1997
/s/Will F. Nicholson, Jr. Will F. Nicholson, Jr.	Director	February 25, 1997
/s/J. Michael Powers J. Michael Powers	Director	February 25, 1997
/s/Thomas E. Rodriguez Thomas E. Rodriguez	Director	February 25, 1997
/s/Rodney E. Slifer Rodney E. Slifer	Director	February 25, 1997
/s/W. Thomas Stephens W. Thomas Stephens	Director	February 25, 1997
/s/Robert G. Tointon Robert G. Tointon	Director	February 25, 1997

EXHIBIT INDEX

2(a)* Merger Agreement and Plan of Reorganization dated August 22, 1995 (Form 8-K dated August 22, 1995, File No. 1-3280 - Exhibit 2).

3(a)1* Restated Articles of Incorporation of the Registrant dated July 9, 1990 (Form S-3, File No. 33-54877 - Exhibit 3(a)).

3(a)2* Articles of Amendment of the Restated Articles of Incorporation of the Registrant dated May 11, 1994 (Form S-3, File No. 33-54877 - Exhibit 3(b)).

3(b)* By-laws dated November 30, 1992 (Form 10-K, 1993 - Exhibit 3(b)).

4(a)(1)* Indenture, dated as of December 1, 1939, providing for the issuance of First Mortgage Bonds (Form 10 for 1946- Exhibit (B-1)).

4(a)(2)* Indentures supplemental to Indenture dated as of December 1, 1939:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.	Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Mar. 14, 1941	10, 1946	B-2	Apr. 25, 1969	8-K, Apr. 1969	1
May 14, 1941	10, 1946	B-3	Apr. 21, 1970	8-K, Apr. 1970	1
Apr. 28, 1942	10, 1946	B-4	Sept. 1, 1970	8-K, Sept. 1970	2
Apr. 14, 1943	10, 1946	B-5	Feb. 1, 1971	8-K, Feb. 1971	2
Apr. 27, 1944	10, 1946	B-6	Aug. 1, 1972	8-K, Aug. 1972	2
Apr. 18, 1945	10, 1946	B-7	June 1, 1973	8-K, June 1973	1
Apr. 23, 1946	10-K, 1946	B-8	Mar. 1, 1974	8-K, Apr. 1974	2
Apr. 9, 1947	10-K, 1946	B-9	Dec. 1, 1974	8-K, Dec. 1974	1
June 1, 1947	S-1, (2-7075)	7(b)	Oct. 1, 1975	S-7, (2-60082)	2(b)(3)
Apr. 1, 1948	S-1, (2-7671)	7(b)(1)	Apr. 28, 1976	S-7, (2-60082)	2(b)(4)
May 20, 1948	S-1, (2-7671)	7(b)(2)	Apr. 28, 1977	S-7, (2-60082)	2(b)(5)
Oct. 1, 1948	10-K, 1948	4	Nov. 1, 1977	S-7, (2-62415)	2(b)(3)
Apr. 20, 1949	10-K, 1949	1	Apr. 28, 1978	S-7, (2-62415)	2(b)(4)
Apr. 24, 1950	8-K, Apr. 1950	1	Oct. 1, 1978	10-K, 1978	D(1)
Apr. 18, 1951	8-K, Apr. 1951	1	Oct. 1, 1979	S-7, (2-66484)	2(b)(3)
Oct. 1, 1951	8-K, Nov. 1951	1	Mar. 1, 1980	10-K, 1980	4(c)
Apr. 21, 1952	8-K, Apr. 1952	1	Apr. 28, 1981	S-16, (2-74923)	4(c)
Dec. 1, 1952	S-9, (2-11120)	2(b)(9)	Nov. 1, 1981	S-16, (2-74923)	4(d)
Apr. 15, 1953	8-K, Apr. 1953	2	Dec. 1, 1981	10-K, 1981	4(c)
Apr. 19, 1954	8-K, Apr. 1954	1	Apr. 29, 1982	10-K, 1982	4(c)
Oct. 1, 1954	8-K, Oct. 1954	1	May 1, 1983	10-K, 1983	4(c)
Apr. 18, 1955	8-K, Apr. 1955	1	Apr. 30, 1984	S-3, (2-95814)	4(c)
Apr. 24, 1956	10-K, 1956	1	Mar. 1, 1985	10-K, 1985	4(c)
May 1, 1957	S-9, (2-13260)	2(b)(15)	Nov. 1, 1986	10-K, 1986	4(c)
Apr. 10, 1958	8-K, Apr. 1958	1	May 1, 1987	10-K, 1987	4(c)
May 1, 1959	8-K, May 1959	2	July 1, 1990	S-3, (33-37431)	4(c)
Apr. 18, 1960	8-K, Apr. 1960	1	Dec. 1, 1990	10-K, 1990	4(c)
Apr. 19, 1961	8-K, Apr. 1961	1	Mar. 1, 1992	10-K, 1992	4(d)
Oct. 1, 1961	8-K, Oct. 1961	2	Apr. 1, 1993	10-Q, June 30, 1993	4(a)
Mar. 1, 1962	8-K, Mar. 1962	3(a)	June 1, 1993	10-Q, June 30, 1993	4(b)
June 1, 1964	8-K, June 1964	1	Nov. 1, 1993	S-3, (33-51167)	4(a)(3)
May 1, 1966	8-K, May 1966	2	Jan. 1, 1994	10-K, 1993	4(a)(3)
July 1, 1967	8-K, July 1967	2	Sept. 2, 1994	8-K, Sept. 1994	4(a)
July 1, 1968	8-K, July 1968	2	May 1, 1996	10Q, June 30, 1996	4(a)

4(a)(3) Supplemental Indenture dated as of November 1, 1996, establishing a series of First Mortgage Bonds under the Indenture dated as of December 31, 1939.

4(b)(1)* Indenture, dated as of October 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, September 30, 1993 - Exhibit 4(a)).

4(b)(2)* Indentures supplemental to Indenture dated as of October 1, 1993:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
November 1, 1993	S-3, (33-51167)	4(b)(2)
January 1, 1994	10-K, 1993	4(b)(3)
September 2, 1994	8-K, Sept. 1994	4(b)
May 1, 1996	10-Q, June 30, 1996	4(b)

4(b)(3) Supplemental Indenture No. 5, dated as of November 1, 1996 establishing a series of Secured Medium-Term Notes under the Indenture dated as of October 1, 1993.

4(c)(1)* Rights Agreement dated as of February 26, 1991, between the Registrant and Mellon Bank, N.A. (Form 8-A, filed on March 1, 1991 - Exhibit 1).

4(c)(2)* Amendment to the Rights Agreement dated August 22, 1995 (Form 8-K dated August 22, 1995, File No. 1-3280 - Exhibit 99(b)).

10(a)(1)* Settlement Agreement dated February 9, 1996 between the Company and the United States Department of Energy (10-K, 195 - Exhibit 10(a)(1)).

10(a)(2)* Settlement Agreement dated June 27, 1979 between the Registrant and General Atomic Company (Form S-7, File No. 2-66484 - Exhibit 5(a)(1)).

10(a)(3)* Services Agreement executed June 27, 1979 and effective as of January 1, 1979 between the Registrant and General Atomic Company (Form S-7, File No. 2-66484 - Exhibit 5(a)(3)).

10(c)(1)* Amended and Restated Coal Supply Agreement entered into October 1, 1984 but made effective as of January 1, 1976 between the Registrant and Amax Inc. on behalf of its division, Amax Coal Company (10-K, 1984 - Exhibit 10(c)(1)).

10(c)(2)* First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective January 1, 1988 between the Registrant and Amax Coal Company (10-K, 1988 -Exhibit 10(c)(2).**

10(e)(1)*+ Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (10-K, 1991 - Exhibit 10(e)(2)).

10(e)(2)*+ Omnibus Incentive Plan, as amended on January 1, 1996 (10-K, 1995 - Exhibit 10(e)(2)).

10(e)(3)*+ Executive Savings Plan (10-K, 1991 - Exhibit 10(e)(5)).

10(e)(4)*+ Form of Key Executive Severance Agreement, as amended on August 22, and November 27, 1995. (10-K, 1995 - Exhibit 10(3)(4)).

10(f)(1)*+ Form of Director's Agreement (10-K, 1987 - Exhibit 10(f)(1)).

10(f)(2)*+ Form of Officer's Agreement (10-K, 1987 - Exhibit 10(f)(2)).

10(g)(1)*+ Employment Agreement dated April 8, 1994 between the Company and Mr. Delwin D. Hock (10-Q, March 31, 1994 - Exhibit 10).

10(g)(2)*+ Employment Agreement dated July 18, 1994 between the Company and Mr. Wayne H. Brunetti(10-Q, September 30, 1994 - Exhibit 10).

10(g)(3)*+ Employment Agreement dated December 5, 1994 between the Company and Ms. Patricia T. Smith (10-K, 1994 - Exhibit 10(g)(3)).

10(g)(4)*+ Employment Agreement dated March 1, 1994 between the Company and Mr. A. Clegg Crawford (10K, 1995 - Exhibit 10(g)(4)).

10(g)(5)*+ Amendment to Employment Agreement dated August 22, 1995 between the Company and Mr. Delwin D. Hock. (10-K, 1995 - Exhibit 10(g)(5)).

10(g)(6)*+ Amendment to Employment Agreement dated August 22, 1995 between the Company and Mr. Wayne H. Brunetti. (10-K, 1995 - Exhibit 10(g)(6)).

10(g)(7)*+ Amendment to Employment Agreement dated August 22, 1995 between the Company and Ms. Patricia T. Smith. (10-K, 1995 - Exhibit 10(g)(7)).

12(a) Computation of Ratio of Consolidated Earnings to Consolidated Fixed Charges is set forth at page 70 herein.

12(b) Computation of Ratio of Consolidated Earnings to Consolidated Combined Fixed Charges and Preferred Stock Dividends is set forth at page 71 herein.

21 Subsidiaries

23 Consent of Arthur Andersen LLP is set forth at page 84 herein.

24 Power of Attorney is set forth at page 84 herein.

27 Financial Data Schedule UT

99 NCE Unaudited Pro Forma Financial Information is set forth at pages 72-77 herein.

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* Previously filed as indicated and incorporated herein by reference.

** Confidential Treatment.

\+ Management contracts of compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(10)(iii) of Regulation S-K.

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