BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Application of PUGET SOUND ENERGY, INC. for (1) Approval of the Proposed Sale of PSE's Share of the Centralia Facilities, and (2) Authorization to Amortize Gain Over a Five-Year Period.	DOCKET NO. UE-99_____ EXHIBIT NO. ____ (WAG-5)

EXHIBIT NO. ____ (WAG-5)
TO THE DIRECT TESTIMONY
OF WILLIAM A. GAINES

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 106
ADMIT ☑ W/D ☐ REJECT ☐

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

X Annual report pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 1998

OR

__ Transition report pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934

Commission File Number 1-4393

PUGET SOUND ENERGY, INC.
(Exact name of registrant as specified in its charter)

WASHINGTON
(State or other jurisdiction of incorporation or organization)

91-0374630
(I.R.S. Employer Identification No.)

411 - 108th Avenue N.E., Bellevue, Washington 98004-5515
(Address of principal executive offices)

(425) 454-6363
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which listed
Common Stock, without par value, $10 stated value	N. Y. S. E
Preference Share Purchase Rights	N. Y. S. E
7.45% Series II, Preferred Stock (Cumulative, $25 Par Value)	N. Y. S. E
8.50% Series III, Preferred Stock (Cumulative, $25 Par Value)	N. Y. S. E

Securities registered pursuant to Section 12(g) of the Act:

Title of each class
Preferred Stock (Cumulative; $100 Par Value)
Preferred Stock (Cumulative; $25 Par Value)
8.231% Capital Securities

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 **X** 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. /**X**/

The aggregate market value of the voting stock held by non-affiliates of the registrant at December 31, 1998, was approximately $2,353,000,000.

The number of shares of the registrant's common stock outstanding at February 26, 1999, was 84,560,548.

Documents Incorporated by Reference

The Company's definitive proxy statement for its 1999 Annual Meeting of Shareholders is incorporated by reference in Part III hereof.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
BPA	Bonneville Power Administration
CAAA	Clean Air Act Amendments
Cabot	Cabot Oil & Gas Corporation
Chelan	Public Utility District No. 1 of Chelan County, Washington
Dth	Dekatherm (One Dth is equal to one MMBTu)
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
KW	Kilowatts
KWH	Kilowatt Hours
MMBTu	One Million British Thermal Units
MW	Megawatts (one MW equals one thousand KW)
MWH	Megawatt Hours
Montana Power	The Montana Power Company
NERC	North American Electric Reliability Council
NMFS	National Marine Fisheries Service
PGA	Purchased Gas Adjustment
PRAM	Periodic Rate Adjustment Mechanism
PRP	Potentially Responsible Party
PUDs	Washington Public Utility Districts
PURPA	Public Utility Regulatory Policies Act
WECo	Washington Energy Company
WEGM	Washington Energy Gas Marketing Company
Washington Commission	Washington Utilities and Transportation Commission
WNG	Washington Natural Gas Company
WSCC	Western Systems Coordinating Council

Part I

Item 1.

BUSINESS

GENERAL

Puget Sound Energy, Inc. (the "Company"), is an investor-owned public utility incorporated in the State of Washington furnishing electric and gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region of Washington state.

At December 31, 1998, the Company had approximately 890,800 electric customers, consisting of 789,800 residential, 95,300 commercial, 4,200 industrial and 1,500 other customers and approximately 543,900 gas customers, consisting of 497,200 residential, 43,600 commercial, 3,000 industrial and 100 other customers. For the year 1998, the Company added approximately 18,900 electric customers and approximately 22,600 gas customers, representing annualized growth rates of 2.2% and 4.3%, respectively. During 1998, the Company's billed retail revenues from electric utility operations were derived 45% from residential customers, 36% from commercial customers, 15% from industrial customers and 4% from other customers, and the Company's retail revenues from gas utility operations were derived 61% from residential customers, 28% from commercial customers, 8% from industrial customers and 3% from other customers. During this period, the largest customer accounted for 2.4% of the Company's utility operating revenues.

The Company is affected by various seasonal weather patterns throughout the year and, therefore, operating revenues and associated expenses are not generated evenly during the year. Variations in energy usage by consumers occur from season to season and from month to month within a season, primarily as a result of weather conditions. The Company normally experiences its highest energy sales in the first and fourth quarters of the year. Sales of electricity to other utilities also vary by quarters and years depending principally upon streamflow conditions for the generation of surplus hydro-electric power, customer usage and the energy requirements of other neighboring utilities. Earnings from electric operations therefore, since the discontinuance of the PRAM in 1996 can be significantly influenced by surplus sales and variations in weather, hydro conditions and non-firm regional electric energy prices. Earnings from gas operations can be significantly influenced by variations in weather. The Company has a Purchased Gas Adjustment ("PGA") mechanism in retail rates to recover variations in gas supply costs. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Rate Matters.")

During the period from January 1, 1994, through December 31, 1998, the Company made gross electric utility plant additions of $729 million and retirements of $154 million. In the five-year period ended December 31, 1998, the Company made gross gas utility plant additions of $481 million and retirements of $52 million. Gross electric utility plant at December 31, 1998, was approximately $3.8 billion which consisted of 47% distribution, 25% generation, 16% transmission and 12% general plant and other. Gross gas utility plant at December 31, 1998, was approximately $1.3 billion which consisted of 82% distribution, 5% transmission and 13% general plant and other.

At year-end the Company had 2,996 aggregate full-time equivalent utility employees.

INDUSTRY OVERVIEW

The electric and gas industries in the United States are undergoing significant changes. The focus of these changes is to promote competition among suppliers of electricity and gas and associated services. In 1996 and 1997, the Federal Energy Regulatory Commission ("FERC") issued orders that require utilities, including the Company, to file open access transmission tariffs that will make the utilities' electric transmission systems available to wholesale sellers and buyers on a non-discriminatory basis. A number of states, including California, have restructured their electric industries to separate or "unbundle" power generation, transmission and distribution in order to permit new competitors to enter the market place. In part because electric rates in the Pacific Northwest have been among the lowest in the nation, certain of the legislatures in this region, including Washington, have not yet enacted laws to provide for competition at the retail level. The

Washington Commission has initiated a pilot program, in which the Company participates, that permits consumers limited direct access to competitive energy suppliers. The Company is actively monitoring developments in this area and has indicated its support for the enactment of legislation that would provide increased choice for electric service customers in the State of Washington.

In order to position itself to respond effectively to future restructuring of the utility industry, and in anticipation of a competitive environment for electric energy sales, the Company in 1997 organized its utility operations into separate business units: energy delivery; energy supply and customer solutions. This reorganization accommodates, if it occurs, legislatively mandated unbundling of power generation from transmission and distribution which would allow customers to purchase these services and commodities individually from different suppliers or, alternatively, as a complete package.

Since 1986, the Company has been offering gas transportation as a separate service to industrial and commercial customers who choose to purchase their gas supply directly from producers and gas marketers. The continued evolution of the natural gas industry, resulting primarily from FERC Orders 436, 500 and 636, has served to increase the ability of large gas end-users to bypass the Company in obtaining gas supply and transportation services. Although the Company has not lost any substantial industrial or commercial load as a result of such bypass, in certain years up to 160 customers annually have taken advantage of unbundled transportation service; in 1998, 123 commercial and industrial customers, on average, chose to use such service.

REGULATION AND RATES

The Company is subject to the regulatory authority of (1) the Washington Commission as to retail rates, accounting, the issuance of securities and certain other matters and (2) the FERC with respect to the transmission of electric energy, the resale of electric energy at wholesale, accounting and certain other matters. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Rate Matters.")

ELECTRIC UTILITY OPERATIONS

At December 31, 1998, the Company's peak electric power resources were approximately 5,145,610 KW. The Company's historical peak load of approximately 4,847,000 KW occurred on December 21, 1998.

During 1998, the Company's total electric energy production was supplied 25% by its own resources, 20% through long-term contracts with several of the Washington Public Utility Districts ("PUDs") that own hydroelectric projects on the Columbia River, 29% from other firm purchases and 26% from non-firm purchases.

The following table shows the Company's electric energy supply resources at December 31, 1998, and energy production during the year:

	Peak Power Resources at December 31, 1998		1998 Energy Production	
	Kilowatts	%	Kilowatt-Hours (Thousands)	%
Purchased Resources:				
Columbia River PUD Contracts (Hydro)	1,416,000	27.5%	6,471,295	20.1%
Other Hydro[1]	573,760	11.2%	3,015,835	9.3%
Other Producers[1]	1,401,900	27.2%	14,836,079	46.0%
Total Purchased	3,391,660	65.9%	24,323,209	75.4%
Company-Owned Resources:				
Hydro	308,200	6.0%	1,231,496	3.8%
Coal	771,900	15.0%	5,746,536	17.8%
Natural gas/oil	673,850	13.1%	956,698	3.0%
Total Company-Owned	1,753,950	34.1%	7,934,730	24.6%
Total	5,145,610	100.0%	32,257,939	100.0%

1 Power received from other utilities is classified between hydro and other producers based on the character of the utility system used to supply the power or, if the power is supplied from a particular resource, the character of that resource.

Company-Owned Electric Generation Resources The Company and other utilities are joint owners of four mine-mouth, coal-fired, steam-electric generating units at Colstrip, Montana, approximately 100 miles east of Billings, Montana. The Company owns a 50% interest (330,000 KW) in Units 1 and 2 and a 25% interest (350,000 KW) in Units 3 and 4. The owners of the Colstrip Units purchase coal for the Units from Western Energy Company ("Western Energy"), an affiliate of Montana Power Company ("Montana Power") (one of the joint owners), under the terms of long-term coal supply agreements. In February 1997, the Company, Montana Power and Western Energy settled a dispute under a power sales agreement between Montana Power and the Company and entered into an agreement to restructure the mines and plants. In the third quarter of 1998, Western Energy, the Company and other joint owners of Units 3 and 4 revised the coal supply contract which reduced the delivered price of coal for Units 3 and 4 and allows for the joint owners to review and approve mining plans and budgets.

In November 1998, the Company announced that it had signed an agreement to sell its interest in the Colstrip plant, as well as associated transmission facilities to PP&L Global, Inc., of Fairfax, Virginia, a subsidiary of PP&L Resources, Inc.

The Company owns a 7% interest (91,900 KW) in a coal-fired, steam-electric generating plant near Centralia, Washington, with a total net capability of 1,313,000 KW. In 1991, the Company and other owners of the Centralia project renegotiated a long-term coal supply agreement with PacifiCorp. The Company and other owners of the Centralia project are reviewing emissions compliance options that will need to be adopted to meet Federal and State emission requirements by the year 2000. The Company has joined with the other owners of the Centralia project in offering for sale its ownership interest in the facility. As part of the sale process, the Centralia owners are reviewing the projected reclamation liability related to the coal mining operations.

The Company also has the following plants with an aggregate net generating capability of 982,050 KW: Upper Baker River hydro project (103,000 KW) constructed in 1959; Lower Baker River hydro project (71,400 KW) reconstructed in 1960; White River hydro plant (63,400 KW) constructed in 1911 with installation of the last unit in 1924; Snoqualmie Falls hydro plant (44,000 KW), half the capability of which was installed during the period 1898 to 1910 and half in 1957; and one smaller hydro plant, Electron (26,400 KW), constructed during the period 1904 to 1929; a standby internal combustion unit (2,750 KW) installed in 1969; an oil-fired combustion turbine unit (67,500 KW) installed in 1974; four dual-fuel combustion turbine units (89,100 KW each) installed during 1981; and two dual-fuel combustion turbine units (123,600 KW each) installed during 1984. All of these generating facilities are located in the Company's service territory.

The Company's combustion turbines installed in 1981 and 1984 may be fueled with either natural gas or distillate oil. Short-term supplies of distillate fuel are stored on-site. These plants are operated from time to time for peaking purposes and to produce energy for sales to other utilities, either directly or through tolling arrangements.

On December 19, 1997, the Company was issued a 50-year license by FERC for its existing and operating White River project which includes authorization to install an additional 14,000 KW generating unit. The Company has filed for a rehearing with FERC on certain articles of the license because certain restrictions placed on the operation of the plant may make it uneconomic to operate. The outcome of the Company's appeal before the FERC is uncertain at this time. The initial license for the existing and operating Snoqualmie Falls project expired in December 1993, and the Company continues to operate this project under a temporary license. The Company is continuing the FERC application process to relicense this project. The Company has also applied for a license to expand its existing 1,750 KW Nooksack Falls project which is currently unlicensed and not operating because of an electric generator fire in 1996.

Columbia River Electric Energy Supply Contracts During 1998, approximately 20.1% of the Company's energy output was obtained at an average cost of approximately 11.5 mills per KWH through long-term contracts with several of the Washington PUDs owning hydroelectric projects on the Columbia River.

The Company's purchases of power from the Columbia River projects is generally on a "cost of service" basis under which the Company pays a proportionate share of the annual debt service and operating and maintenance costs of each project in proportion to the amount of power annually purchased by the Company from such project. Such payments are not contingent upon the projects being operable. These projects are financed through substantially level debt service payments, and their annual costs may vary over the term of the contracts as additional financing is required to meet the costs of major maintenance, repairs or replacements or license requirements.

The Company has contracted to purchase from Chelan County PUD ("Chelan") a share of the output of the original units of the Rock Island Project which equaled 54.9% through June 30, 1998. This share decreases gradually to 50% of the output at July 1, 1999, and remains unchanged thereafter for the duration of the contract. The Company has also contracted to purchase the entire output of the additional Rock Island units for the duration of the contract, except that the Company's share of output of the additional units may be reduced up to 10% per year beginning July 1, 2000, subject to a maximum aggregate reduction of 50%, upon the exercise of rights of withdrawal by Chelan for use in its local service area. Chelan has given notice of withdrawal of 5% on July 1, 2000. As of December 31, 1998, the Company's aggregate annual capacity from all units of the Rock Island Project was 480,000 KW. The Company has contracted to purchase from Chelan 38.9% (505,000 KW as of December 31, 1998) of the annual output of the Rocky Reach Project, which percentage remains unchanged for the remainder of the contract. The Company's share of the annual output of the Wells Project purchased from Douglas County PUD is currently 31.3% (261,000 KW as of December 31, 1998) upon the additional exercise of withdrawal rights by Douglas County PUD. The Company has contracted to purchase from Grant County PUD 8.0% (72,000 KW as of December 31, 1998) of the annual output of the Priest Rapids project and 10.8% (98,000 KW as of December 31, 1998) of the annual output of the Wanapum project, which percentages remain unchanged for the remainder of the contracts. (See Note 17 to the Company's Consolidated Financial Statements.)

In 1964, the Company and fifteen other utilities and agencies in the Pacific Northwest entered into a long-term coordination agreement extending until June 30, 2003 (the "Coordination Agreement"). This agreement provides for the coordinated operation of substantially all of the hydroelectric power plants and reservoirs in the Pacific Northwest. A new Coordination Agreement was negotiated in 1997 and will replace the prior agreement in February 1999. Various fishery enhancement measures, including most recently the 1995 "biological opinion" from the National Marine Fisheries Service ("NMFS"), have reduced the flexibility provided by the Coordination Agreement. (See "Environment - Federal Endangered Species Act.")

Certain utilities in the northwest United States and Canada are obtaining the benefits of additional firm power as a result of the ratification of a 1961 treaty between the United States and Canada under which Canada is providing approximately 15,500,000 acre-feet of reservoir storage on the upper Columbia River. As a result of this storage, streamflow which would otherwise not be usable to serve firm regional load is stored and later released during periods when it is usable. Pursuant to the treaty, one-half of the firm power benefits produced by the additional storage accrue to Canada. The Company's benefits from this storage are based upon its percentage participation in the Columbia River projects and one-half of those benefits must be returned to Canada. Also in 1961, the Company contracted to purchase 17.5% of Canada's share of the power to be returned resulting from such storage until a phased expiration of the contract from 1998 through 2003. The Company has also contracted to purchase from the Bonneville Power Administration ("BPA") supplemental capacity in amounts that decrease gradually until a phased expiration of the contract from 1998 through 2003. In 1997, the Company entered into agreements with the Mid-Columbia PUDs which specify the amount of the Company's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the earlier of the expiration of the PUD contracts or 2024.

Electric Energy Supply Contracts and Agreements With Other Utilities Under a 1985 settlement agreement relating to Washington Public Power Supply System ("WPPSS") Nuclear Project No. 3, in which the Company had a 5% interest, the Company is receiving from BPA for approximately 30.5 years, beginning January 1, 1987, electric power during the months of November through April. Under the contract, the Company is guaranteed to receive not less than 191,667 MWH in each contract year until the Company has received total deliveries of 5,833,333 MWH.

On April 4, 1988, the Company executed a 15-year contract, with provisions for early termination by the Company, for the purchase of firm energy supply from Avista Corporation (formerly Washington Water Power Company). This agreement calls for the delivery of 100 MW of capacity and 657,000 MWH of energy from the Avista system annually (75 annual average MW). Minimum and maximum delivery rates are prescribed. Under this agreement, the energy is to be priced at Avista's average generation and transmission cost, subject to certain price ceilings.

On October 27, 1988, the Company executed a 15-year contract for the purchase of firm power and energy from PacifiCorp. Under the terms of the agreement, the Company receives 120 average MW of energy and 200 MW of peak capacity.

On November 23, 1988, the Company executed an agreement to purchase surplus firm power from BPA. Under the agreement, the Company receives 150 average MW of energy and 300 MW of peak capacity from BPA between October 1 and March 31 of each contract year. In 1997, the Company elected to terminate the agreement on June 30, 2001, the date that the purchase was to convert to a summer-winter exchange.

On October 1, 1989, the Company signed a contract with Montana Power under which Montana Power provides the Company, from its share of Colstrip Unit 4, 7[illegible] average MW of energy (94 MW of peak capacity) over a 21-year period. On February 27, 1995, the Company delivered to Montana Power notice of termination of the contract based on Montana Power's failure to arrange for firm contractual transmission rights for such energy as required by the contract. Pursuant to a settlement between the Company and Montana Power on February 21, 1997, the contract remains in effect and the price of power purchased by the Company is reduced. The settlement also addressed certain price reductions and restructuring activities in connection with the Colstrip coal supply arrangements.

On December 11, 1989, the Company executed a conservation transfer agreement with Snohomish County PUD. Snohomish County PUD, together with Mason and Lewis County PUDs, will install conservation measures in their service areas. The agreement calls for the Company to receive the power saved over the expected 20-year life of the measures. The agreement calls for BPA to deliver the conservation power to the Company from March 1, 1990, through June 30, 2001, and for Snohomish County PUD to deliver the conservation power for the remaining term of the agreement. Annual power deliveries gradually increased over the first five years of the agreement and will remain at 6 average MW of energy throughout the remaining term of the agreement.

The Company executed an exchange agreement with Pacific Gas & Electric Company which became effective on January 1, 1992. Under the agreement, 300 MW of capacity together with 413,000 MWH of energy are exchanged seasonally every year on a unit for unit basis. No payments are made under this agreement. Pacific Gas & Electric Company is a summer peaking utility and will provide power during the months of November through February. The Company is a winter peaking utility and will provide power during the months of June through September. Each party may terminate the contract for various reasons. The Company has obtained 400,000 KW of transmission rights (similar in nature to ownership type rights) on the Pacific Northwest-Southwest AC Intertie to California. These transmission rights which are used, in part, to transmit power under this agreement, have been subject to unanticipated limitations and curtailments over the past several years. The Company is working with BPA to obtain a restoration of these rights and compensation for damages.

In October 1997 a 10-year power exchange agreement between the Company and Powerex (a subsidiary of a British Columbia utility) became effective. Under this agreement Powerex pays the Company for the right to deliver power to the Company at the Canadian border in exchange for the Company delivering power to Powerex at various locations in the United States. The Company also obtained 425,000 KW of transmission rights (similar in nature to ownership type rights) on the Westside Northern Intertie to Canada in October 1997. These transmission rights which are used, in part, to transmit power under this agreement have been subject to unanticipated limitations and curtailments. The Company is working with BPA to obtain a restoration of these rights.

Electric Energy Supply Contracts and Agreements With Non-Utilities As required by the federal Public Utility Regulatory Policies Act ("PURPA"), the Company entered into long-term firm purchased power contracts with non-utility generators. The most significant of these are the five contracts described below which the Company entered into in 1989, 1990 and 1991 with operators of natural gas-fired cogeneration projects. The Company purchases the net electrical output of these five projects at fixed and annually escalating prices which were intended to approximate the Company's avoided cost of new generation projected at the time these agreements were made. Principally as a result of dramatic changes in natural gas price levels, the power purchase prices under these agreements are significantly above the current market price of power and, based upon projections of future market prices, are expected to remain well above market for the duration of the contracts. The Company's estimated payments under these five contracts are \$280 million for 1999, \$284 million for 2000, \$308 million for 2001, \$313 million for 2002, \$318 million for 2003 and in the aggregate, \$2.4 billion thereafter through 2012. These payments reflect the Tenaska contract restructuring described below. The Company continues to seek restructuring of the other four contracts. If retail electric energy prices move to market levels as a result of electric industry restructuring, the Company plans to seek to continue to recover in rates the above market portion of these contract costs.

On June 29, 1989, the Company executed a 20-year contract to purchase 70 average MW of energy and 80 MW of capacity, beginning October 11, 1991, from the March Point Cogeneration Company ("March Point"), which owns and operates a natural gas-fired cogeneration facility known as March Point Phase I, located at a Texaco refinery in Anacortes, Washington. On December 27, 1990, the Company executed a second contract (having a term coextensive with the first contract) to purchase an additional 53 average MW of energy and 60 MW of capacity, beginning in January 1993, from another natural gas-fired cogeneration facility owned and operated by March Point, which facility is known as March Point Phase II and is located at the Texaco refinery in Anacortes, Washington.

On February 24, 1989, the Company executed a 20-year contract to purchase 108 average MW of energy and 123 MW of capacity, beginning in April 1993, from Sumas Cogeneration Company, L.P., which owns and operates a natural gas-fired cogeneration project located in Sumas, Washington.

On September 26, 1990, the Company executed a 15-year contract to purchase 141 average MW of energy and 160 MW of capacity, beginning in July 1993, from Encogen Northwest L.P. ("Encogen," a limited partnership having a general partner that is a subsidiary of Enserch Development Corp.), which owns and operates a natural-gas fired cogeneration facility located at the Georgia Pacific mill near Bellingham, Washington.

On March 20, 1991, the Company executed a 20-year contract to purchase 216 average MW of energy and 245 MW of capacity, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates a natural-gas fired cogeneration project located near Ferndale, Washington. In December 1997 and January 1998, the Company and Tenaska Washington Partners entered into revised agreements which will lower purchased power costs from the Tenaska project by restructuring its natural gas supply. The Company paid $215 million to buy out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices that were well above current and projected future market prices for natural gas. The Company became the principal natural gas supplier to the project and power purchase prices under the Tenaska contract were revised to reflect market-based prices for the natural gas supply. The Company obtained an order from the Washington Commission creating a regulatory asset related to the $215 million restructuring payment. Under terms of the order, the Company is allowed to accrue as an additional regulatory asset one-half the carrying costs of the deferred balance over the first five years. These revised arrangements are expected to reduce the Company's power supply costs from the Tenaska project between 15 and 20 percent annually over the remaining 13-year life of the contract, net of the costs of the restructuring payment. The Company's purchased electric energy cost associated with the Tenaska contract was $80.1 million in 1998.

Energy Trading On April 1, 1998, the Company and Duke Energy Trading and Marketing ("DETM") of Houston, a unit of Duke Energy Corp., signed an agreement relating to energy-marketing and trading activities in 14 western states and British Columbia. The purpose of this agreement is to coordinate the two companies' activities in serving Puget Sound Energy's native power load with DETM's western power and natural gas marketing and trading operations. The companies share the benefits of this coordination proportionally up to certain stipulated amounts intended to be reflective of the value the companies would have realized from their respective operations in the absence of the agreement. The companies share equally any benefits created above the stipulated amounts.

Under the terms of the agreement, DETM performs the forward electric energy trading function. As a result, the Company's future wholesale "sales to other utilities" revenues and related "secondary purchase" power expenses, which previously have reflected trading activity by the Company, will be lower than amounts which the Company would report absent this agreement. During 1998, the Company continued to execute in its own name transactions in which electric energy is delivered within the next 30 days. Therefore, the Company's results include those transactions. The Company recorded its share of the benefits that result from the agreement as a credit to purchased power expense. The agreement provides that forward trading activities will be conducted according to DETM's energy price risk and credit policies, and that the Company is not responsible for any losses caused by deviation from these policies. The Company and DETM are presently considering modifications to the agreement.

Electric Rates and Regulation The order approving the merger of the Company, Washington Energy Company and Washington Natural Gas Company ("Merger"), issued by the Washington Commission on February 5, 1997, contains a rate plan designed to provide a five-year period of rate certainty for customers and to provide the Company with an opportunity to achieve a reasonable return on investment. General electric tariff rates were stipulated to increase between 1.0% to 1.5% depending on rate class on January 1, 1999 through 2001, while those for certain customers will increase by 1.5% in 2002.

ELECTRIC UTILITY OPERATING STATISTICS

Year Ended on December 31	1998	1997	1996	1995	1994
Operating revenues by classes (thousands):					
Residential	$ 540,549	$ 529,990	$ 554,318	$ 524,748	$ 532,124
Commercial	431,752	414,480	423,139	397,211	375,751
Industrial	180,959	166,473	170,596	168,501	163,574
Other consumers	42,952	32,453	44,125	38,730	38,759
Operating revenues billed to consumers[1]	1,196,212	1,143,396	1,192,178	1,129,190	1,110,208
Unbilled revenues - net increase (decrease)	4,024	(4,921)	13,201	(6,382)	(2,522)
PRAM accrual	—	(40,777)	(74,326)	3,955	25,835
Total operating revenues from consumers	1,200,236	1,097,698	1,131,053	1,126,763	1,133,521
Other utilities and marketers	274,972	133,726	67,716	52,567	60,537
Total operating revenues	$ 1,475,208	$ 1,231,424	$ 1,198,769	$ 1,179,330	$ 1,194,058
Number of customers (average):					
Residential	782,095	767,476	754,097	739,173	723,566
Commercial	94,118	91,517	89,613	87,404	85,203
Industrial	4,193	4,090	3,993	3,908	3,851
Other	1,437	1,389	1,371	1,346	1,325
Total customers (average)	881,843	864,472	849,074	831,831	813,945
KWH generated, purchased and interchanged (thousands):					
Company generated	7,934,730	6,641,118	5,585,595	6,371,416	7,011,932
Purchased power	24,231,978	22,611,963	20,573,983	17,897,922	16,268,042
Interchanged power (net)	91,230	103,959	99,942	48,485	(87,771)
Total energy output	32,257,938	29,357,040	26,259,520	24,317,823	23,192,203
Losses and company use	(1,413,331)	(1,414,101)	(1,322,262)	(1,235,457)	(1,291,322)
Total energy sales	30,844,607	27,942,939	24,937,258	23,082,366	21,900,881

1 Operating revenues in 1998, 1997, 1996 and 1995 were reduced by $46.7 million, $40.5 million, $41.0 million and $25.1 million, respectively, as a result of the Company's sale of $237.7 million of its investment in customer-owned energy conservation measures. (See "Operating revenues – Electric" in Management's Discussion and Analysis and Note 1 to the Consolidated Financial Statements.)

(continued from previous page)

Year Ended on December 31	1998	1997	1996	1995	1994
Electric energy sales, KWH (thousands):					
Residential	9,313,652	9,319,508	9,350,292	8,972,498	8,913,903
Commercial	7,191,164	7,022,092	6,807,465	6,538,533	6,301,568
Industrial	4,072,722	3,994,748	3,793,966	3,720,641	3,724,931
Other consumers	284,312	206,330	205,066	205,232	200,622
Total energy billed to consumers	20,861,850	20,542,678	20,156,789	19,436,904	19,141,024
Unbilled energy sales - net increase (decrease)	43,027	(45,556)	224,412	(158,920)	(72,352)
Total energy sales to consumers	20,904,877	20,497,122	20,381,201	19,277,984	19,068,672
Sales to other utilities and marketers	9,939,730	7,445,817	4,556,057	3,804,382	2,832,209
Total energy sales	30,844,607	27,942,939	24,937,258	23,082,366	21,900,881
Per residential customer:					
Annual use (KWH)	11,909	12,143	12,399	12,139	12,319
Annual billed revenue	$721.09	$716.88	$762.35	$726.95	$735.42
Billed revenue per KWH	$.0606	$.0590	$.0615	$.0599	$.0597
Company-owned generation capability - KW:					
Hydro	308,200	309,950	309,950	309,950	309,950
Steam	771,900	771,900	771,900	771,900	771,900
Natural gas/oil	673,850	702,350	702,350	702,350	702,350
Total	1,753,950	1,784,200	1,784,200	1,784,200	1,784,200
Heating degree days	4,498	4,599	4,953	3,994	4,341
% of normal of 30 year average	91.6%	93.7%	100.9%	81.4%	88.4%
Load factor	52.6%	58.7%	55.5%	56.7%	54.7%

GAS UTILITY OPERATIONS

Gas Supply The Company currently purchases a blended portfolio of long-term firm, short-term firm, and spot gas supplies from a diverse group of major and independent producers and gas marketers in the United States and Canada. All of the Company's gas supply is ultimately transported through Northwest Pipeline Corporation ("NPC"), the sole interstate pipeline delivering directly into the western Washington area.

Peak Firm Gas Supply at December 31, 1998	Dth per Day	%
Purchased Gas Supply		
British Columbia	212,400	27.8
Alberta	75,900	9.9
United States	50,900	6.7
Total Purchased Gas Supply	339,200	44.4
Purchased Storage Capacity		
Clay Basin	89,900	11.8
Jackson Prairie	47,700	6.2
LNG	69,600	9.1
Total Purchased Storage Capacity	207,200	27.1
Owned Storage Capacity		
Jackson Prairie	188,400	24.6
Propane-Air Injection	30,000	3.9
Total Owned Storage Capacity	218,400	28.5
Total Peak Firm Gas Supply	764,800	100.0

All supplies and storage are connected to PSE's market with firm transportation capacity.

For baseload and peak-shaving purposes, the Company supplements its firm gas supply portfolio by purchasing natural gas at generally lower prices in summer, injecting it into underground storage facilities and withdrawing it during the winter heating season. Storage facilities at Jackson Prairie in Western Washington and at Clay Basin in Utah are used for this purpose. Peaking needs are also met by using Company-owned gas held in NPC's liquefied natural gas ("LNG") facility at Plymouth, Washington, and by producing propane-air gas at a plant owned by the Company and located on its distribution system.

In 1998, the Company took assignment from Cascade Natural Gas of a Peaking Gas Supply Service ("PGSS") contract whereby the Company can divert up to 48,000 MMBTu per day of gas supply away from the Tenaska Cogeneration Facility and toward the core gas load by causing Tenaska to operate its facility on distillate fuel and paying any additional costs of such operation.

The Company expects to meet its firm peak-day requirements for residential, commercial and industrial markets through its firm gas purchase contracts, firm transportation capacity, firm storage capacity and other firm peaking resources. The Company believes that it will be able to acquire incremental firm gas supply resources which are reliable and reasonably priced, to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

Gas Supply Portfolio For the 1998-99 winter heating season, the Company has contracted for approximately 28% of its expected peak-day gas supply requirement from sources originating in British Columbia under a combination of long-term and winter-peaking purchase agreements. Long-term gas supplies from Alberta represent approximately 10% of the peak-day requirement. Long-term and winter peaking arrangements with U.S. suppliers and gas stored at Clay Basin make up approximately 18% of the peak-day portfolio. The balance of the peak-day requirement is expected to be met with gas stored at Jackson Prairie, LNG held at NPC's Plymouth facility and propane-air resources, which represent approximately 31%, 9% and 4%, respectively, of expected peak-day requirements.

During 1998, approximately 46% of gas supplies purchased by the Company originated from British Columbia while 27% originated in Alberta and 27% originated in the U.S.

The current firm, long-term gas supply portfolio consists of arrangements with 16 producers and gas marketers, with no single supplier representing more than 15% of expected peak-day requirements. Contracts have remaining terms ranging from less than one year to 13 years, with an average term of 2 years. All gas supply contracts contain market-sensitive pricing provisions based on several published indices.

The Company's firm gas supply portfolio is structured to capitalize on regional price differentials when they arise. Gas and services are marketed outside the Company's service territory ("off-system sales") whenever on-system customer demand requirements permit. The geographic mix of suppliers and daily, monthly and annual take requirements permit a high degree of flexibility in selecting gas supplies during off-peak periods to minimize costs.

Gas Transportation Capacity The Company currently holds firm transportation capacity on pipelines owned by NPC and PG&E Gas Transmission-Northwest, formerly known as Pacific Gas Transportation ("PGT"). Accordingly, the Company pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

The Company holds firm capacity on NPC's pipeline totaling 454,533 Dekatherms per day (one Dekatherm "Dth" is equal to one million British thermal units or "MMBTu" per day), acquired under several agreements at various times. The Company has exchanged certain segments of its firm capacity with third parties to effectively lower transportation costs. The Company's firm transportation capacity contracts with NPC have remaining terms ranging from 6 to 17 years. However, the Company has either the unilateral right to extend the contracts under their current terms or the right of first refusal to extend such contracts under current FERC orders. The Company's firm transportation capacity on PGT's pipeline has a remaining term of 25 years.

Gas Storage Capacity The Company holds storage capacity in the Jackson Prairie and Clay Basin underground gas storage facilities adjacent to NPC's pipeline. The Jackson Prairie facility, operated and one-third owned by the Company, is used primarily for intermediate peaking purposes, able to deliver a large volume of gas over a relatively short time period. Combined with capacity contracted from NPC's one-third stake in Jackson Prairie, the Company has peak, firm delivery capacity of over 230,000 Dth per day and total firm storage capacity exceeding 6,000,000 Dth at the facility. The location of the Jackson Prairie facility in the Company's market area provides significant cost savings by reducing the amount of annual pipeline capacity required to meet peak-day gas requirements. The Company, as project operator of the facility, received approval from FERC on September 30, 1998, to expand the Jackson Prairie facility. The Company's share of the expanded project will provide additional firm delivery capacity of over 100,000 Dth per day and additional firm storage capacity of above 1,000,000 Dth at the start of the 1999-2000 heating season. The Company has secured rights to additional firm seasonal pipeline capacity to be utilized in conjunction with the expanded project.

The Clay Basin storage facility is supply area storage and is withdrawn over the entire winter, capturing savings due to injecting lower cost gas supplies during the summer. The Company has maximum firm withdrawal capacity of over 100,000 Dth per day from the facility with total storage capacity exceeding 13,000,000 Dth. The capacity is held under two contracts with remaining terms of 15 and 21 years.

LNG and Propane-Air Resources LNG and propane-air resources provide gas supply on short notice for short periods of time. Due to their high cost, these resources are utilized as the supply of last resort in extreme peak-demand periods, typically lasting a few hours or days. The Company has long-term contracts for storage of nearly 250,000 Dth of Company-owned gas as LNG at NPC's Plymouth facility, which equates to approximately three and one-half days' supply at maximum daily deliverability of 70,500 Dth. The Company owns storage capacity for approximately 1.4 million gallons of propane. The propane-air injection facilities are capable of delivering the equivalent of 30,000 Dth of gas per day for up to four days directly into the Company's distribution system.

Capacity Release FERC provided a capacity release mechanism as the means for holders of firm pipeline and storage entitlements to relinquish temporarily unutilized capacity to others in order to recoup all or a portion of the cost of such capacity. Capacity may be released through several methods including open bidding and by pre-arrangement. The Company continues to successfully mitigate a substantial portion of the demand charges related to both storage and NPC and PGT pipeline capacity not utilized during off-peak periods. WNG CAP I, a wholly owned subsidiary of the Company, was formed to provide additional flexibility and benefits from capacity release. Washington Energy Gas Marketing Company ("WEGM"), a wholly-owned subsidiary of the Company, also markets excess capacity on the PGT pipeline. (See Note 17 to the Consolidated Financial Statements.)

Gas Rates and Regulation The order approving the Merger, issued by the Washington Commission on February 5, 1997, contains a rate plan which provided unchanged rates for all classes of natural gas customers until January 1, 1999, when rates decreased by 1% on gas utility margins.

On March 25, 1998, the WUTC approved the Company's Purchase Gas Adjustment ("PGA") and deferral amortization (true-up) filing effective April 1, 1998. The PGA filing reflected a reduction in expected gas costs of approximately $4.3 million. The deferral amortization filing was a refund to customers for prior period over-collections of gas costs. This filing replaced a larger deferral amortization refund that had been in effect since May 1995. The combined filings reduced gas rates to all sales customers less than 1%.

On June 25, 1998, the Company received approval from the Washington Commission to begin a new performance-based mechanism for strengthening its gas-supply purchasing and gas-storage practices. The PGA Incentive Mechanism, which encourages competitive gas purchasing and management of pipeline and storage-capacity became effective July 1, 1998. Incentive gains and losses from the three-year program are shared between customers and shareholders. After the first $0.5 million, which is allocated to customers, gains and losses are shared 40%/60% between the Company and customers up to $26.5 million, and 33%/67% thereafter. Gains or losses are determined relative to a weighted average index which is reflective of the Company's gas supply and transportation contract costs. The Company's share of incentive gains under the PGA Incentive Mechanism in 1998 were approximately $1.1 million while customers received approximately $2.0 million.

GAS UTILITY OPERATING STATISTICS

Twelve Months Ended December 31	1998	1997	1996	1995	1994
Operating revenues by classes (thousands):					
Regulated utility sales:					
Residential sales	$ 253,169	$ 246,747	$ 238,560	$ 231,202	$ 206,602
Commercial firm sales	96,116	97,233	94,251	97,396	91,749
Industrial firm sales	18,557	19,524	20,024	25,860	28,827
Interruptible sales	22,190	19,832	23,376	44,511	51,425
Transportation services	14,211	14,631	12,812	10,762	8,399
Other	12,308	11,480	11,085	10,317	9,405
Total gas operating revenues	$ 416,551	$ 409,447	$ 400,108	$ 420,048	$ 396,407
Customers, average number served					
Residential	486,553	465,185	440,586	423,195	403,642
Commercial firm	42,273	41,158	39,651	38,378	37,112
Industrial firm	2,850	2,839	2,762	2,754	2,824
Interruptible	940	962	1,000	1,037	1,009
Transportation	123	128	106	55	36
Total customers (average)	532,739	510,272	484,105	465,419	444,623
Gas volumes (thousands of therms):					
Residential sales	444,611	434,179	421,727	398,283	371,472
Commercial firm sales	193,765	195,087	188,321	179,725	174,668
Industrial firm sales	42,737	44,563	46,640	55,365	62,698
Interruptible sales	72,115	60,244	72,229	132,316	151,175
Transportation volumes	254,368	277,092	242,299	156,941	119,590
Total gas volumes	1,007,596	1,011,165	971,216	922,630	879,603
Working-gas volumes in storage at year end (thousands of therms):					
Jackson Prairie	37,683	52,430	65,834	65,834	65,834
Clay Basin	58,827	64,930	82,847	130,970	47,557
Average use per customer (therms):					
Residential	914	933	957	941	921
Commercial firm	4,584	4,740	4,749	4,683	4,708
Industrial firm	14,995	15,697	16,886	20,103	22,035
Interruptible	76,718	62,624	72,229	127,595	147,315
Transportation	2,068,033	2,164,781	2,285,840	2,853,473	3,400,694

(continued from previous page)

TWELVE MONTHS ENDED DECEMBER 31	1998	1997	1996	1995	1994
Average revenue per customer:					
Residential	$ 520	$ 530	$ 541	$ 546	$ 512
Commercial firm	2,274	2,362	2,377	2,538	2,472
Industrial firm	6,511	6,877	7,250	9,390	10,208
Interruptible	23,606	20,615	23,376	42,923	50,966
Transportation	115,537	114,305	120,868	195,673	233,306
Average revenue per therm (cents):					
Residential	56.9¢	56.8¢	56.6¢	58.0¢	55.6¢
Commercial firm	49.6	49.8	50.0	54.2	52.5
Industrial firm	43.4	43.8	42.9	46.7	46.0
Interruptible	30.8	32.9	32.4	33.6	34.0
Total sales to customers	51.8	52.2	51.6	52.1	49.8
Transportation	5.6	5.3	5.3	6.9	7.0
Weather - degree days	4,498	4,599	4,953	3,994	4,341
% of normal (30-year average)	91.6%	93.7%	100.9%	81.4%	88.4%

Note: Data prior to January 1, 1997, is for the period ending September 30.

ENERGY CONSERVATION

The Company offers programs designed to help new and existing customers use energy efficiently. The primary emphasis is to provide information and technical services to enable customers to make energy-efficient choices with respect to building design, equipment and building systems, appliance purchases and operating practices.

Since May 1997, the Company has recovered electric energy conservation expenditures through a tariff rider mechanism. The rider mechanism allows the Company to defer the conservation expenditures and amortize them to expense as the Company concurrently collects the conservation expenditures in rates over a one year period. As a result of the rider, there is no effect on earnings per share.

Since 1995, the Company has been authorized by the Washington Commission to defer gas energy conservation expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows the Company to defer conservation expenditures and recover them in rates over the subsequent year. The tracker mechanism also allows the Company to recover an Allowance for Funds Used to Conserve Energy (AFUCE) on any outstanding balance that is not being recovered in rates.

ENVIRONMENT

The Company's operations are subject to environmental regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental and energy laws and regulations, the Company cannot determine the impact such laws may have on its existing and future facilities. (See Note 17 to the Consolidated Financial Statements for further discussion of environmental sites.)

Federal Clean Air Act Amendments of 1990 The Company has an ownership interest in coal-fired, steam-electric generating plants at Centralia, Washington and Colstrip, Montana, which are subject to the federal Clean Air Act Amendments of 1990 ("CAAA") and other regulatory requirements.

The Centralia Project and the Colstrip Projects met the sulfur dioxide limits of the CAAA in Phase I (1995). The Company and other joint owners of the Centralia Project are exploring alternative emission compliance options and project economics in light of compliance costs to meet the Phase II limits in the year 2000. All four units at the Colstrip Project, operated by Montana Power, meet Phase II emission limits.

The Company owns combustion turbine units, most of which are capable of being fueled by either natural gas or oil. The nature of these units provides operational flexibility in meeting air emission standards. There is no assurance that in the future environmental regulations affecting sulfur dioxide or nitrogen oxide emissions may not be further restricted, or that restrictions on emissions of carbon dioxide or other combustion by-products may not be imposed.

Federal Endangered Species Act In November 1991, the National Marine Fisheries Service ("NMFS") listed the Snake River Sockeye as an endangered species pursuant to the federal Endangered Species Act ("ESA"). Since the Sockeye listing, the Snake River fall and spring/summer Chinook have also been listed as threatened. In response to the listings, a team of experts was formed to develop a plan for the recovery needs of these species. In 1995, the NMFS issued a biological opinion which has significantly changed the operation of the Federal Columbia River Power System.

The plans developed by NMFS affect the Mid-Columbia projects from which the Company purchases power on a long-term basis, and will further reduce the flexibility of the regional hydro-electric system. Although the full impacts are unknown at this time, the plan developed by NMFS shifts an amount of the Company's generation from the Mid-Columbia projects from winter periods into the spring when it is not needed for system loads, and will increase the potential for spill and loss of generation at the Mid-Columbia projects.

Since the 1991 listings, one more species of salmon has been listed and two more have been proposed which may further influence operations. Upper Columbia River Steelhead were listed by NMFS in August 1997. Anticipating the Steelhead listing, the Mid-Columbia PUDs initiated consultation with the federal and state agencies, Native American tribes and non-governmental organizations to secure operational protection through a long-term settlement and habitat conservation plan which includes fish protection and enhancement measurement for the next 50 years. The negotiations have concluded among the Chelan and Douglas County PUDs and various fishery agencies, and final agreement is subject to a National Environmental Policy Act review and power purchaser approval. Generally, the agreement obligates the PUDs to achieve certain levels of passage efficiency for downstream migrants at their hydroelectric facilities and to fund certain habitat conservation measures. Grant County PUD has yet to reach agreement on these issues.

The proposed listings of Puget Sound Chinook salmon and spring Chinook for the upper Columbia will be final, if approved, in March 1999. The listing of spring Chinook for the upper Columbia should not result in markedly differing conditions for operations from previous listings in the area. However, Puget Sound has not experienced ESA listing to date and listing of Puget Sound Chinook could cause a number of changes to operations of government agencies and private entities in the region including the Company. These may adversely affect hydro plant operations, permit issuance for facilities construction and increased costs for process and facilities. Because the Company relies substantially less on hydro-electric energy from the Puget Sound area than from the Mid-Columbia and because the impact on the Company operations in the Puget Sound area is not likely to impair significant generating resources, the impact of listing for Puget Sound Chinook salmon should be proportionately less than the Columbia River listings.

EXECUTIVE OFFICERS AT DECEMBER 31, 1998

Name	Age	Offices
W. S. Weaver	54	President & Chief Executive Officer since January 1998; President May 1997 - January 1998; Vice Chairman and Chairman of Unregulated Subsidiaries, February 1997 - May 1997; Executive Vice President and Chief Financial Officer 1991-1997; Director since 1991.
R. R. Sonstelie	53	Chairman of the Board since February 1997; President and Chief Executive Officer 1992-1997; President and Chief Operating Officer 1991-1992; President and Chief Financial Officer 1987-1991; Executive Vice President 1985-1987; Senior Vice President Finance 1983-1985; Vice President Engineering and Operations 1980-1983; Director since 1987.
J. W. Eldredge	48	Chief Accounting Officer since 1994; Corporate Secretary and Controller since 1993; Controller since 1988.
D. E. Gaines	41	Treasurer since 1994; Director Strategic Planning 1992-1994; Manager Financial Planning 1986 - 1992.
W. A. Gaines	43	Vice President Energy Supply since February 1997; Manager Power Management 1996-1997; Manager Operations Planning 1986-1996.
D.A. Graham	58	Vice President Human Resources since April 1998; Director Human Resources 1989-1998.
R. L. Hawley	49	Vice President and Chief Financial Officer since March 1998. For more than five years prior to that time, he was a partner with Coopers & Lybrand L.L.P. (now PricewaterhouseCoopers LLP).
T. J. Hogan	47	Vice President Systems Operations since February 1997; Washington Energy Company positions held: Executive Vice President and Chief Operating Officer 1995-1997; Vice President Supply, Administration and Corporate Secretary 1994-1995; Vice President Legal and Corporate Secretary 1991-1994.
S. A. McKeon	52	Vice President and General Counsel since June 1997. For more than five years prior to that time he was a partner at Perkins Coie LLP.
S. McLain	42	Vice President Corporate Performance since December 1997; Director Planning and Work Practices 1997; various positions in Human Resources, Operations, Customer Service and Strategic Planning 1988-1997.
J. Quintana	50	Vice President External Affairs since April 1998. For more than five years prior to that time, he was Sr. Vice President Public Affairs for the Rockey Company, a public relations consulting firm.
G. B. Swofford	57	Vice President Customer Operations since February 1997; Senior Vice President Customer Operations 1994-1997; Vice President Divisions and Customer Services 1991-1994; Vice President Rates and Customer Programs 1986-1991.

Officers are elected for one-year terms.

Item 2.
PROPERTIES

The principal electric generating plants and underground gas storage facilities owned by the Company are described under Item 1 - "Business - Electric Utility Operations and Gas Utility Operations." The Company owns its transmission and distribution facilities and various other properties. Substantially all properties of the Company are subject to the liens of the Company's Mortgage Indentures.

Item 3.
LEGAL PROCEEDINGS

See Note 17 to the Consolidated Financial Statements.

Item 4.
SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

Part II
Item 5.
MARKET FOR REGISTRANT'S COMMON EQUITY
and Related Stockholder Matters

The Company's common stock is traded on the New York Stock Exchange (symbol PSD). The number of stockholders of record of the Company's common stock at December 31, 1998, was 58,650.

The Company has paid dividends on its common stock each year since 1943 when such stock first became publicly held. Future dividends will be dependent upon earnings, the financial condition of the Company and other factors.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in the Company's Articles of Incorporation and electric and gas mortgage indentures. Under the most restrictive covenants, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $183 million at December 31, 1998. (See Note 7 to the Consolidated Financial Statements.)

Dividends paid and high and low stock prices for each quarter over the last two years were:

	1998			1997[1]		
	Price Range		Dividends	Price Range		Dividends
Quarter Ended	High	Low	Paid	High	Low	Paid
March 31	30-1/4	26-5/8	$.46	26	23-1/2	$.46
June 30	28-5/8	25	$.46	26-1/2	23-3/4	$.46
September 30	28	24-1/16	$.46	26-15/16	25-1/8	$.46
December 31	29	25-7/8	$.46	30-3/16	25-1/2	$.46

1 Data for Puget Sound Power & Light Company prior to February 10, 1997

Item 6.

SELECTED FINANCIAL DATA

(Dollars in thousands except per share data) Year ended December 31	1998	1997	1996	1995	1994
Operating revenue	$ 1,907,340	$ 1,676,902	$ 1,649,279	$ 1,631,118	$ 1,632,485
Operating income	298,980	215,866	284,474	270,344	224,772
Income from continuing operations	169,612	125,698	167,351	128,381	79,312
Income for common stock from continuing operations	156,609	107,421	145,170	105,727	58,929
Basic and diluted earnings per common share from continuing operations (Note 1 to the financial statements)	1.85	1.28	1.72	1.26	0.70
Dividends per common share	1.84	1.78	1.67	1.67	1.67
Book value per common share	16.00	16.06	16.31	16.27	17.01
Total assets at year-end	$ 4,720,689	$ 4,493,370	$ 4,227,470	$ 4,244,568	$ 4,496,770
Long-term obligations	1,474,748	1,411,707	1,165,584	1,230,499	1,253,498
Redeemable preferred stock	73,162	78,134	87,839	89,039	91,242
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	100,000	100,000	—	—	—

Item 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS

of Financial Condition and Results of Operations

The following discussion of the Company's business includes some forward-looking statements that involve risks and uncertainties. Words such as "estimates," "expects," "anticipates," "plans," and similar expressions identify forward-looking statements involving risks and uncertainty. Those risks and uncertainties include, but are not limited to, the ongoing restructuring of the electric and gas industries and the outcome of regulatory proceedings related to that restructuring. The ultimate impacts of both increased competition and the changing regulatory environment on future results are uncertain, but are expected to fundamentally change how the Company conducts its business. The outcome of these changes and other matters discussed below may cause future results to differ materially from historic results, or from results or outcomes currently expected or sought by the Company.

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Financial condition and results of operations for 1998 and 1997 reflect the results of Puget Sound Energy, Inc., formerly Puget Sound Power & Light Company ("Puget"). Financial condition and results of operations for 1996 reflect combined results for the fiscal years ended December 31 for Puget and September 30 for Washington Energy Company ("WECO"). On February 10, 1997, WECO and its subsidiary, Washington Natural Gas Company, merged into Puget, which then changed its name to Puget Sound Energy, Inc.

Net income in 1998 was $169.6 million on operating revenues of $1.907 billion, compared to $123.1 million on operating revenues of $1.677 billion in 1997 and $165.5 million on operating revenues of $1.649 billion in 1996. Income for common stock was $156.6 million in 1998, compared to $105.7 million in 1997 and $143.3 million in 1996.

Basic and diluted earnings per share in 1998 were $1.85 on 84.6 million weighted average common shares outstanding compared to $1.25 on 84.6 million weighted average common shares outstanding in 1997 including a $.03 loss per share from discontinued operations and $1.70 on 84.4 million weighted average common shares outstanding in 1996 including a $.02 loss per share from discontinued operations.

Contributing to the increase in net income and basic and diluted earnings per share in 1998 compared to 1997 were continued growth in retail electric and gas customers and a reduction in utility operations and maintenance expense of approximately $13.6 million or 5% in 1998 compared to 1997. Net income for 1997 included an after-tax charge of $36.3 million ($0.43 cents per share) for costs related to the merger including transaction expenses, employee separation and system and facilities integration. Net income in 1997 also included an after-tax charge of $2.6 million ($0.03 per share), to write off the Company's remaining investment in undeveloped coal reserves and related activities in southeastern Montana (See Note 18 to the Consolidated Financial Statements). These charges in 1997 were partially offset by $13.6 million ($0.16 cents per share) related to an income tax refund received in 1997. Excluding the impact of these charges and credits to income, continuing operations for 1997 produced earnings of $1.55 per share. Total kilowatt-hour sales to ultimate consumers in 1998 were 20.9 billion, compared with 20.5 billion in 1997 and 20.4 billion in 1996. Kilowatt-hour sales to other utilities were 9.9 billion in 1998, 7.4 billion in 1997 and 4.6 billion in 1996.

Total gas volumes sold, including transported gas, were 1,008 million therms in 1998, 1,011 million therms in 1997 and 971 million therms in 1996.

Increase (Decrease) Over Preceding Year

YEARS ENDED DECEMBER 31 (DOLLARS IN MILLIONS)	1998	1997	1996
Operating revenues:			
General rate increases	$ 18.5	$ 16.9	$ —
PRAM electric revenue surcharges/refunds	44.8	(22.6)	(37.1)
BPA Residential Purchase and Sale Agreement	(1.2)	2.7	(15.8)
Electric sales to other utilities	141.2	66.0	15.1
Electric revenue sold to conservation trust	(6.2)	0.5	(15.9)
Electric load and other changes	46.7	(30.8)	73.1
Gas revenue change	7.1	9.3	(19.9)
Other revenues	(20.5)	(14.4)	18.7
Total operating revenue changes	230.4	27.6	18.2
Operating expenses:			
Energy costs:			
Purchased electricity	137.2	52.6	38.8
Residential exchange	16.4	31.2	(15.1)
Purchased gas	(3.5)	1.6	(41.3)
Electric generation fuel	15.1	0.8	5.0
Utility operations and maintenance	(13.6)	8.3	(16.6)
Other operations and maintenance	(13.6)	(11.0)	2.7
Depreciation and amortization	3.7	17.6	3.2
Merger and related costs	(55.8)	51.0	4.8
Taxes other than federal income taxes	1.2	4.1	6.3
Federal income taxes	60.2	(60.0)	16.2
Total operating expense changes	147.3	96.2	4.0
Other income	(18.9)	26.5	16.4
Interest charges	20.3	(0.5)	(8.3)
Discontinued operations	2.6	(0.8)	24.8
Net income changes	$ 46.5	$ (42.4)	$ 63.7

The following information pertains to the changes outlined on the table on the preceding page:

Operating Revenues - Electric Electric operating revenues increased $18.5 million in 1998 and $16.9 million in 1997 when compared to the prior years due to an overall average 1.8% general rate increase effective February 8, 1997 and an overall average 1.2% general rate increase effective January 1, 1998.

Electric operating revenues in 1998 increased $44.8 million compared to 1997 as a result of a $48.6 million Periodic Rate Adjustment Mechanism ("PRAM") revenue reduction in 1997 associated with an IRS 1991-1994 Conservation tax refund and related interest income. Based on the Company's agreement with the Washington Commission, the benefit of the tax refund was passed on to retail customers as a reduction of the PRAM accrued revenue balance. The $48.6 million reduction in revenues in 1997 was offset by a decrease in federal, state and local taxes as well as a decrease in interest expense and a recognition of interest income.

On September 30, 1996, the PRAM was discontinued pursuant to a negotiated settlement and the Washington Commission issued an order granting a joint motion by the Company and the Washington Commission staff to transfer annual revenues of $165.5 million which were being collected in PRAM rates to the Company's permanent rate schedules. A $17.0 million overcollection of the PRAM, which resulted from the pass-through of conservation tax refunds, was refunded to customers in 1997.

Electric revenues in 1998, 1997 and 1996 were reduced because of the credit that the Company received through the Residential Purchase and Sale Agreement with the Bonneville Power Administration ("BPA"). This agreement enables the Company's residential and small farm customers to receive the benefits of lower-cost federal power. A related reduction is included in purchased and interchanged power expenses. On January 29, 1997, the Company and the BPA signed a Residential Exchange Termination Agreement. The Agreement ends the Company's participation in the Residential Purchase and Sale Agreement with BPA. As part of the Termination Agreement, the Company will receive payments by the BPA of approximately $235 million over an approximately 5-year period ending June 2001. Under the rate plan approved by the Washington Commission in its merger order, the Company will continue to reflect through the rate stability period in customers' bills, the current level of Residential Exchange benefits. Over the remainder of the Residential Exchange Termination Agreement from January 1999 through June 2001, it is projected that the Company will credit customers approximately $172.3 million more than it will receive from BPA during the following periods:

Period	Dollars in Millions
January – December 1999	$68.0
January – December 2000	67.4
January – June 2001	36.9
	$172.3

The Company and other investor owned utilities in the northwest region are participating in the BPA's subscription process pursuant to which allocations of federal power in the northwest beginning in 2001 will be determined. Through this process the Company may receive a combination of low cost energy from the federal power system in the northwest or financial exchange agreements for the benefit of their residential and small farm customers, which would be in lieu of the residential and small farm customer benefits required by the Regional Power Act of 1980. The amount of such BPA power purchases and financial exchange arrangements that may be available for the Company's residential and small farm customers, and the BPA rates and contractual terms and conditions applicable therto, are generally not established at this time. Subsequent to the rate stability period, the Company intends to seek regulatory approval to pass through benefits equal to amounts received from the BPA to its residential and small farm customers.

Electric revenues in 1998, 1997 and 1996 were reduced by $46.7 million, $40.5 million and $41.0 million, respectively, as a result of the Company's sale of revenues associated with $237.7 million of its investment in conservation assets to a grantor trust. The revenue decrease represents the portion of rate revenues that were sold and forwarded to the trust. The impact of this revenue decrease, however, was offset by related reductions in other utility operations and maintenance and interest expenses.

To meet customer demand, the Company's power supply portfolio includes net purchases of power under long-term supply contracts. However, depending principally upon streamflow available for hydro-electric generation and weather effects on customer demand, from time to time the Company may have surplus power available for sale at wholesale to other utilities. In addition, the Company has increased its wholesale surplus power business through short and intermediate-term purchases, sales, arbitrage and other trading and marketing techniques. Sales to other utilities increased $141.2 million, $66.0 million and $15.1 million in 1998, 1997 and 1996, respectively, due primarily to increased wholesale power transactions. Wholesale sales generally have small margins. However, there may be certain times when the market price of power may cause margins to fluctuate.

Operating Revenues – Gas Regulated gas utility sales revenue in 1998 increased by $7.1 million from the prior year on a 2.6% increase in gas volumes sold. Total gas volumes, including transported gas, decreased 0.35% in 1998 from 1997. The increase in sales revenue was primarily the result of a 4.4% increase in gas customers during 1998, decreases in industrial and transportation sales volumes with lower prices and margins and an increase in residential firm and commercial sales with higher prices and margins. Utility gas margin (the difference between gas revenues and gas purchases) increased by $10.6 million, or 4.6 %, in 1998 over 1997.

Regulated gas utility sales revenue in 1997 increased by $9.3 million, or 2.3%, from the prior year on a 0.7% decrease in gas volumes sold. Total gas volumes, including transported gas, increased 4.1% in 1997 from 1996. Regulated gas utility sales revenue in 1996 decreased by $19.9 million, or 4.7%, from the prior year on a 4.8% decrease in gas volumes sold. Total gas volumes, including transported gas, increased 5.3% in 1996. Other revenues decreased $20.5 million in 1998 compared to 1997 and $14.4 million in 1997 from 1996 due primarily to the sale of an unregulated subsidiary (Washington Energy Services Company) in October 1997.

Operating Expenses Purchased electricity expenses increased $137.2 million in 1998 when compared to 1997 and $52.6 million in 1997 when compared to 1996. The increase in 1998 was due primarily to a $112.3 million increase in secondary power purchases from other utilities to support wholesale sales and increased payments of $18.8 million for firm power purchases from non-utility generators. The increase in 1997 was the result of increased secondary power purchases from other utilities of $47.5 million and a $5.4 million increase in transmission wheeling and associated costs compared to 1996. The increase in 1996 of $3.8 million over 1995 was the result of higher payments for firm power purchases from non-utility generators and increased secondary power purchases from other utilities.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with BPA decreased $16.4 million in 1998 when compared to 1997. The primary reason for the decrease was the Residential Exchange Termination Agreement between the Company and BPA in January 1997. Residential exchange credits decreased $31.2 million in 1997 as compared to 1996 and increased $15.1 million in 1996 as compared to 1995. Residential exchange credits received in 1998 were $55.6 million and are estimated to be $39.0 million, $41.0 million and $27.0 million in the years 1999 through 2001. (See discussion of the Residential Purchase and Sale Agreement under Operating Revenues.)

Purchased gas expenses decreased $3.5 million in 1998 compared to 1997 despite the 2.6% increase in gas volumes sold. This was primarily the result of a $5.4 million credit to purchased gas costs in the fourth quarter of 1998 due to a true-up of gas costs through the PGA mechanism.

Purchased gas expenses increased $1.6 million in 1997 compared to 1996 as a result of a 0.7% increase in gas volumes sold.

Purchased gas expenses decreased $41.3 million in 1996 compared to 1995. The decrease resulted from the lower average per-therm cost of gas established in the May 1995 PGA and the 5% reduction in gas volumes sold.

Electric generation fuel expense increased $15.1 million in 1998 primarily due to the Company generating more electricity at Company-owned gas-fired combustion turbine plants. These increases were partially offset by reductions to Colstrip fuel expense. In September 1998, the Company recorded a reduction of $4.9 million in fuel expense and $3.5 million of interest income related to the resolution of outstanding issues with the Colstrip fuel supplier.

Electric generation fuel expense increased $5.0 million in 1996 compared to 1995. The increase was due in part to an arbitration panel's decision in 1995 of a dispute involving the coal supply agreement at the Company's 50% owned Colstrip 1 and 2 plants that resulted in a $4.6 million decrease to fuel expense recorded in the first quarter of 1995. In addition, the Company recorded a one-time charge of $1.8 million in the second quarter of 1996 relating to a loss on the sale of oil stocks at a combustion turbine site.

Utility operations and maintenance expenses decreased $13.6 million in 1998 compared to 1997. The decrease is primarily the result of improved operating efficiencies.

Utility operations and maintenance expenses increased $8.3 million in 1997 compared to 1996 and decreased $16.6 million in 1996 compared to 1995. The changes were largely the result of an $11.6 million decrease in amortization expense in 1995 associated with the Company's conservation program. In June 1995, the Company sold, to a grantor trust, approximately $202.5 million of its investment in customer-owned energy conservation measures.

Other operations and maintenance expenses decreased $13.6 million in 1998 compared to 1997 and $11.0 million in 1997 compared to 1996. The decreases resulted primarily from the sale of the Company's unregulated subsidiary, Washington Energy Services Company, in October 1997.

Depreciation and amortization expense increased $3.7 million in 1998 compared to 1997. Depreciation and amortization expense due to capital spending related to adding customers, distribution and transmission system improvements and computer software amortization increased $12.3 million in 1998. Partially offsetting these increases in 1998 were decreases from 1997 as a result of an August 1997 Washington Commission Order which authorized the Company to record interest income of $8.3 million related to a conservation tax refund, but required the Company to expense deferred storm damage costs in the amount of $7.4 million and establish a $1.0 million reserve to cover the costs of a Company retail pilot program.

Depreciation and amortization expense increased $17.6 million in 1997 compared to 1996 due primarily to capital spending related to adding customers and transmission and distribution system improvements. In addition, the aforementioned Washington Commission Order resulted in a write-off of deferred storm damage costs in the amount of $7.4 million and the establishment of a $1.0 million reserve to cover the costs of a Company retail pilot program.

Depreciation and amortization expense increased $3.2 million in 1996 compared to 1995 due primarily to new plant placed in service.

Taxes other than federal income taxes increased $4.1 million in 1997 compared to 1996 and $6.3 million in 1996 compared to 1995. The increases were primarily due to higher state property tax payments and higher revenue-based municipal and state excise tax payments.

Federal income taxes in 1997 were $60.2 million less than in 1998 and $60.0 million less than in 1996 as a result of the following factors. An IRS tax refund related to the method of accounting for taxes on conservation expenditures during the first quarter of 1997 decreased federal income taxes by $26.5 million. In addition, there was a $17.0 million reduction associated with a decrease in PRAM revenues of $48.6 million. Merger costs expensed in the first quarter of 1997 further reduced federal income taxes by $19.3 million.

Federal income taxes increased by $16.2 million in 1996 over 1995. The increase was primarily due to higher pre-tax utility earnings. Also, there was a decrease in energy conservation expenditures in 1996 which are deducted for federal income taxes.

Other Income Other income, net of federal income tax, decreased $18.9 million in 1998 from 1997. The decrease was due primarily to the receipt of interest income in 1997 of $13.6 million from the IRS on tax refunds for prior years in connection with a plant abandonment loss, conservation tax refunds and certain additional research and experimental credits claimed for tax purposes.

Other income, net of federal income tax, increased $26.5 million in 1997 from 1996. The increase was due primarily to interest income received from the IRS on tax refunds for prior years as explained in the preceding paragraph. Other income for 1997 includes after-tax losses of $1.0 million and $5.3 million related to the sale of an unregulated subsidiary (Washington Energy Services Company) and operations of a subsidiary, ConneXt, respectively.

Total other income increased $16.4 million in 1996 as compared to 1995. The increase is due primarily to pre-tax charges in 1995 related to Cabot totaling $24.8 million, partially offset by a $8.7 million deferred tax benefit of write-downs.

Interest Charges Interest charges, which consist of interest and amortization on long-term debt and other interest, increased $20.3 million in 1998 compared to 1997 primarily as a result of the issuance of $300 million 7.02% Senior Medium-Term Notes, Series A, in December 1997, the issuance of $100 million 8.231% Capital Trust Debentures in June 1997 and the issuance of $200 million 6.74% Senior Medium-Term Notes, Series A, in June 1998. These increases were partially offset by the maturity of $151 million Secured Medium-Term Notes during the 15 months ended December 31, 1998 and the redemption of $30 million 9.14% Secured Medium-Term Notes, Series A, in June 1998.

Interest charges decreased $0.5 million in 1997 compared to 1996. Interest and amortization on long-term debt increased $2.4 million which included dividend payments on the Company-obligated, mandatorily redeemable preferred securities of $4.7 million. Interest on short-term debt decreased $1.5 million and capitalized interest (AFUDC) increased $1.3 million.

Interest charges decreased $8.3 million in 1996 compared to 1995. Interest and amortization on long-term debt decreased $8.8 million. Contributing to the reduced interest expense were five First Mortgage Bond retirements or redemptions totaling $151 million over the previous 17 months. Other interest expense increased in 1996 over 1995 due primarily to increased interest on PGA balances.

CONSTRUCTION, CAPITAL RESOURCES AND LIQUIDITY

Current construction expenditures, primarily transmission and distribution-related, are designed to meet continuing customer growth. Construction expenditures in 1998 and 1999 also include costs of new accounting and customer information systems. Construction expenditures, which include energy conservation expenditures and exclude AFUDC, were $333.3 million in 1998. The Company expects construction expenditures for the period 1999 through 2001 will be approximately $303 million, $259 million and $252 million, respectively. Construction expenditure estimates are subject to periodic review and adjustment.

The Company expects cash from operations (net of dividends and AFUDC) during the period 1999 through 2001 will, on average, be approximately 68.4% of average estimated construction expenditures (excluding AFUDC) during the same period.

In June 1998, the Company issued $200 million 6.74% Senior Medium-Term Notes, Series A, and redeemed $30 million 9.14% Secured Medium-Term Notes, Series A, due June 2001 at a redemption price of 100%.

In September 1998, the Company filed a shelf-registration statement with the Securities and Exchange Commission for the offering, on a delayed or continuous basis, of up to $500 million principal amount of Senior Notes secured by a pledge of First Mortgage Bonds. On March 9, 1999, the Company issued $250 million principal amount of Senior Medium-Term Notes, Series B, which consisted of $150 million principal amount due March 9, 2009 at an interest rate of 6.46% and $100 million principal amount due March 9, 2029 at an interest rate of 7.0%

The Company's ability to finance its future construction program is dependent upon market conditions and maintaining a level of earnings sufficient to permit the sale of additional securities. In determining the type and amount of future financings, the Company may be limited by restrictions contained in its electric and gas mortgage indentures, Articles of Incorporation and certain loan agreements.

Under the most restrictive tests, at December 31, 1998, the Company could issue either (i) approximately $731 million of additional first mortgage bonds, (ii) approximately $853 million of additional preferred stock at an assumed dividend rate of 5.5%, or (iii) a combination thereof.

Short-term borrowings from banks and the sale of commercial paper are used to provide working capital for the construction program. At December 31, 1998, the Company had available $375 million in lines of credit with various banks, which provide credit support for outstanding commercial paper and bank borrowing of $142 million and $25 million, respectively, effectively reducing the available borrowing capacity under these lines of credit to $208 million. (See Note 9 to the Consolidated Financial Statements.)

Under the most restrictive covenants in the Company's Articles of Incorporation and electric and gas mortgage indentures, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $183 million at December 31, 1998.

RATE MATTERS – ELECTRIC

The order approving the Merger, issued by the Washington Commission on February 5, 1997, contains a rate plan designed to provide a five-year period of rate certainty for customers and to provide the Company with an opportunity to achieve a reasonable return on investment. General electric tariff rates were stipulated to increase between 1.0% to 1.5% depending on rate class on January 1 of 1999 through 2001, while those for certain customers will increase by 1.5% in 2002.

On September 22, 1995, the Washington Commission issued a rate order relating to the Company's fifth annual rate adjustment under the PRAM. In addition, on September 30, 1996, the Washington Commission issued an order granting a joint motion by the Company and the Washington Commission Staff to transfer annual revenues of $165.5 million which were being collected in PRAM rates to the Company's permanent rate schedules. As a result of the order, the Company also wrote off $4.5 million in previously accrued revenues related to special industrial customer service contracts. PRAM accrued revenues of $40.5 million, recorded at December 31, 1996, were recovered in the first quarter of 1997. Over-collection of PRAM revenues were refunded to customers in the second quarter of 1997.

With the discontinuance of the PRAM, the Company no longer has a rate adjustment mechanism to adjust for changes in energy or fuel costs or variances in hydro and weather conditions. These variances may now significantly influence earnings.

On July 8, 1998, the Washington Commission approved the Company's requested accounting treatment for its program to reduce costly tree-caused power outages. The Tree Watch program, which focuses on controlling vegetation outside the Company's rights-of-way, should improve service reliability for its customers and result in future savings in outage recovery costs. The five-year, $43 million program will be treated as an investment that will be amortized over ten years. The Company expects the Tree Watch investment to be offset by savings from lower outage restoration and storm damage costs over the same period.

RATE MATTERS – GAS

The order approving the Merger, issued by the Washington Commission on February 5, 1997, contains a rate plan which provided unchanged rates for all classes of natural gas customers until January 1, 1999, when rates decreased by 1% on gas utility margins. (See Note 1 to the Consolidated Financial Statements for a description of the Company's PGA mechanism.)

YEAR 2000 CONVERSION

Background The Year 2000 issue results from the use of two digits rather than four digits in computer hardware and software to define the applicable year. If not corrected on computer systems that must process dates both before and after January 1, 2000, two-digit year fields may create processing errors or system failures. The Company expects to be Year 2000 ready which means that all mission-critical systems, devices, applications and business relationships have been evaluated and are suitable for continued use into and beyond the Year 2000, or contingency plans are in place.

Project Approach and Progress The Company has established a central project team to coordinate all Year 2000 activities and identified exposure in three categories: information technology; embedded chip technology; and external non-compliance by customers and suppliers. The project team is taking a phased approach in conducting the Year 2000 project for its internal systems. The phases include inventory, assessment, planning/prioritizing, remediation, testing, implementation and contingency planning. In addition, the Company has engaged outside consultants and technicians to aid in formulating and implementing its plan. All business units have completed the inventory phase, and with the exception of the Company's customer information system ("CIS"), discussed below, assessment is 95% complete for all business units, with remediation, testing and implementation scheduled to be completed during the second quarter of 1999.

The Company has been upgrading mainframe and client server financial and business applications since 1997 and replacing many of its business systems as part of its business plans following its merger in 1997. In September, 1998, the Company implemented a Systems, Applications, Products in Data Processing ("SAP") business system which includes essentially all of the Company's business applications with the exception of its CIS. This SAP system is Year 2000 compliant. The remainder of applications and operating environments, excluding the CIS, are in the remediation/testing phase. Full implementation of those applications and components of the Company's internal systems are scheduled for completion by mid-year 1999.

A new CIS which is designed to be Year 2000 compliant is currently being developed by the Company. Development is expected to be completed in 1999. The Company has also begun implementation activities with respect to the new system which will continue during 1999. The Company has also elected to remediate critical elements of its existing CIS for Year 2000 compliance purposes. The Company has formed a specialized team which has completed the inventory phase and currently is conducting assessment and remediation activities for the existing system. The Company expects to complete the assessment phase of this project early in May of 1999 followed immediately by remediation and testing activities which are expected to be completed in the third quarter of 1999.

A specialized embedded systems team has been formed by the Company to inventory, assess and remediate microprocessor technology in its generation, transmission and distribution systems for both gas and electric operations. The inventory and assessment phases of the project are complete. Although some remediation planning is still in process, significant remediation efforts are underway and proceeding according to schedule. Testing and implementation are scheduled to be completed by the end of the second quarter of 1999. Contingency planning specific to the Year 2000 issue began in November 1998, and initial reports were submitted to the Washington Commission and the North American Electric Reliability Council ("NERC"). These plans will be refined and updated as remediation and test results are analyzed, and are scheduled for finalization in the third quarter of 1999.

The Company is also communicating with suppliers, financial institutions and other business partners to coordinate Year 2000 conversion and determine the extent to which the Company is exposed to third-party compliance failures. Approximately 85% of vendors and suppliers have been contacted to date. All third-party assessment is scheduled to be completed in March 1999.

In addition, the Company is working with various industry groups including the NERC and the regional reliability council, the Western Systems Coordinating Council ("WSCC") during the millennium transition. The United States Department of Energy has asked NERC to assume a leadership role in preparing the U.S. electric industry for the transition to the Year 2000.

Costs While the replacement of business systems under business plans developed as a result of the Merger are not included in the Company's Year 2000 project, those replacements substantially reduce the number of internal business applications that require remediation. In addition to the costs of replacing new business systems, the Company has expended approximately $3.6 million through December 31, 1998, on Year 2000 remediation efforts, exclusive of internal labor costs. Although it is difficult to determine the total remaining costs of implementing the Year 2000 plan, the Company's current estimate is approximately $14 million, of which approximately $3 million will be capitalized.

Risk Assessment The electric power supply systems of North America are connected into three major interconnections called grids. The western grid covers the western third of the U.S., western Canada and parts of Mexico. The BPA is the largest supplier of transmission services in the Pacific Northwest. Operational component failures of any entity connected to the grid could cause other failures in that grid. The Company will need to continue to assess this risk as the millennium approaches to evaluate the likelihood of power failures and develop approaches for mitigating the risk of failures.

Much of the natural gas and electric distribution systems are comprised of wires, poles and pipes containing no embedded chips. However, these systems do employ some computer components that could be affected by the Year 2000 transition. Since many of the components used by the Company exist in multiple sub-station locations, there is a risk that a component could be missed, a component manufacturer could provide erroneous information, or the component (while deemed and tested compliant) could fail in a specific configuration found at the Company. The Company has formed a special team to handle these types of components (embedded systems), and has retained an independent engineering firm with specific utility experience to assist in the effort. Results of assessment to date reveal that there are fewer components that are not Year 2000 ready than initially thought. This is consistent with industry findings published in the NERC report to the Department of Energy dated January 11, 1999.

The failure to correct a material Year 2000 problem could result in an interruption in, or a failure of, Company business activities or operations. Such failures could materially and adversely affect the Company's results of operations, liquidity and financial condition. Due to the general uncertainty inherent in the Year 2000 problem, resulting in part from the uncertainty of the Year 2000 readiness of third-party suppliers and customers, the Company is unable to determine at this time whether the consequences of Year 2000 failures will have a material impact on the Company's results of operations, liquidity or financial condition. The Year 2000 project is expected to significantly reduce the Company's level of uncertainty about the Year 2000 problem and the Year 2000 readiness of its material vendors. The Company believes that, with the implementation of new business systems and completion of the project as scheduled, the possibility of significant interruptions of normal operations should be reduced.

As discussed above, elements of the Company's current CIS are not Year 2000 compliant. If the current CIS remediation activities are not succesful by the year 2000, certain normal business activities such as customer billing and collections could be adversely affected by interruptions.

Contingency Plans The Company is identifying various scenarios that could occur in the event that Year 2000 issues are not resolved in a timely manner. These efforts will build upon the work in scenario development and contingency planning that is being done by the WSCC contingency planning task force. A specialized team is being formed that will develop contingency plans and update existing emergency preparedness plans to identify and address risk scenarios for the Company. Contingency planning is scheduled to continue through the third quarter of 1999.

Forward-Looking Statements Readers are cautioned that forward-looking statements contained in the Year 2000 update are based on management's best estimates and may be influenced by factors that could cause actual outcomes and results to be materially different than projected. Specific factors that might cause differences between the estimates and actual results include, but are not limited to, the availability and cost of personnel trained in these areas, the ability to locate and correct all relevant computer code, timely responses to and corrections by third-parties and suppliers, the ability to implement new systems in a timely manner, the ability to implement interfaces between the new systems and the systems not being replaced, and similar uncertainties. Due to the general uncertainty inherent in the Year 2000 problem, resulting in part from the uncertainty of the Year 2000 readiness of third-parties and the interconnection of global businesses, the Company cannot ensure its ability to timely and cost-effectively resolve problems associated with Year 2000 issues that may affect its operations and business, or expose it to third-party liability.

INDUSTRY OVERVIEW

The electric and gas industries in the United States are undergoing significant changes. The focus of these changes is to promote competition among suppliers of electricity and gas and associated services. In 1996 and 1997, the Federal Energy Regulatory Commission ("FERC") issued orders that require utilities, including the Company, to file open access transmission tariffs that will make the utilities' electric transmission systems available to wholesale sellers and buyers on a non-discriminatory basis. A number of states, including California, have restructured their electric industries to separate or "unbundle" power generation, transmission and distribution in order to permit new competitors to enter the marketplace. In part because electric rates in the Pacific Northwest have been among the lowest in the nation, certain of the legislatures in this region, including Washington, have not yet enacted laws to provide for competition at the retail level. The Washington Commission has initiated a pilot program, in which the Company participates, that permits consumers limited direct access to competitive energy suppliers. The Company is actively monitoring developments in this area and has indicated its support for the enactment of legislation that would provide increased choice for all electric service customers in the State of Washington.

In order to better position itself to respond to customer needs and future restructuring of the utility industry, and in anticipation of a competitive environment for electric energy sales, the Company in 1997 organized its utility operations into separate business units: energy delivery; energy supply; and customer solutions.

The Company has an Optional Large Power Sales Rate and certain "special contracts" for its largest customers. Customers who elect the Optional Large Power Sales Rate are no longer considered "core" customers, and the Company no longer has an obligation to plan for future resources to serve their needs. The non-core customers receive access to electric energy that is priced at current market cost and pay a charge for energy delivery (including a charge for conservation programs) and a transition charge (representing the difference between the Company's present cost and the current market cost of electric energy and capacity). The transition charge will be phased out before the end of the year 2000. Non-core customers also take on the risk that market costs could become volatile and that electricity could be unavailable on the open market. In November 1998, a number of industrial customers filed a complaint with the Washington Commission that the Company was incorrectly billing for energy under the Optional Large Power Sales Rate. If the Washington Commission finds that the Company used an incorrect index, the Company would owe approximately $2.6 million in refunds. However, management believes the proper index has been used and expects the Company will prevail on this issue.

Since 1986 the Company has been offering gas transportation as a separate service to industrial and commercial customers who choose to purchase their gas supply directly from producers and gas marketers. The continued evolution of the natural gas industry, resulting primarily from FERC Orders 436, 500 and 636, has served to increase the ability of large gas end-users to bypass the Company in obtaining gas supply and transportation services. Though the Company has not lost any substantial industrial or commercial load as a result of such bypass, in certain years up to 160 customers annually have taken advantage of unbundled transportation service. During 1998, an average of 123 commercial and industrial customers chose to use such service.

OTHER

On March 20, 1991, the Company executed a 20-year contract to purchase 216 average MW of energy and 245 MW of capacity, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates a natural-gas fired cogeneration project located near Ferndale, Washington. In December 1997 and January 1998, the Company and Tenaska Washington Partners entered into revised agreements which will lower purchased power costs from the Tenaska project by restructuring its natural gas supply. The Company paid $215 million to buy out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices that were well above current and projected future market prices for natural gas. The Company became the principal natural gas supplier to the project and power purchase prices under the Tenaska contract were revised to reflect market-based prices for the natural gas supply. The Company obtained an order from the Washington Commission creating a regulatory asset related to the $215 million restructuring payment. Under terms of the order, the Company is allowed to accrue as an additional regulatory asset one-half the carrying costs of the deferred balance over the first five years. These revised arrangements are expected to reduce the Company's power supply costs from the Tenaska project between 15 and 20 percent annually over the remaining 14-year life of the contract, net of the costs of the restructuring payment. The Company's purchased electric energy cost associated with the Tenaska contract was $80.1 million in 1998.

On April 1, 1998, the Company and Duke Energy Trading and Marketing ("DETM") of Houston, a unit of Duke Energy Corp., signed an agreement relating to energy-marketing and trading activities in 14 western States and British Columbia. The purpose of this agreement is to coordinate the two companies' activities in serving Puget Sound Energy's native power load with DETM's Western power and natural gas marketing and trading operations. The companies share the benefits of this coordination proportionally up to certain stipulated amounts intended to be reflective of the value the companies would have realized from their respective operations in the absence of the agreement. The companies share equally any benefits created above the stipulated amounts.

Under the terms of the agreement, DETM performs the forward electric energy trading function. As a result, the Company's future wholesale "sales to other utilities" revenues and related "secondary purchase" power expenses, which previously have reflected trading activity by the Company, will be lower than amounts which the Company would report absent this agreement. During 1998 the Company continued to execute in its own name transactions in which electric energy is delivered within the next 30 days. Therefore, the Company's results include those transactions. The Company recorded its share of the benefits that resulted from the agreement as a credit to Purchased Power Expense. The agreement provides that forward trading activities will be conducted according to DETM's energy price risk and credit policies, and that the Company is not responsible for any losses caused by deviation from these policies. The Company and DETM are presently considering modifications to the agreement.

On November 2, 1998, the Company announced it signed an agreement to sell the Company's 735-megawatt interest in the four-unit, coal-fired Colstrip generation plant in eastern Montana, as well as associated transmission facilities. The Company signed the agreement with PP&L Global, Inc., of Fairfax, Virginia, a subsidiary of PP&L Resources, Inc. Included in the sale are the Company's 50% interest in Colstrip Units 1 and 2; 25% interest in Units 3 and 4; and associated Colstrip transmission capacity across Montana. The sales price is expected to be $549 million before taxes and expenses. The net book value of these assets and related regulatory assets is approximately $464 million. After consideration of taxes and other costs, the gain on the sale is expected to be approximately $37.6 million. The Company expects the Colstrip sale to close in the second half of 1999. Completion of the sale is contingent on receipt of acceptable regulatory treatment from the Washington Commission and the FERC.

The Company has also agreed to join with the other owners of the coal-fired generating plant at Centralia, Washington, by offering for sale its 92 megawatt ownership interest in the facility. As part of the sale process, the Centralia owners are reviewing the projected reclamation liability related to the coal mining operations.

In the fourth quarter of 1998, the Company incurred $4.7 million of transmission and distribution repair costs in connection with restoring electric service following a severe wind storm that occurred on November 23, 1998. Under an order established by the Washington Commission, these costs were deferred for collection in future rates.

For a discussion of Issue 98-10, "Accounting For Contracts Involved in Energy Trading and Risk Management Activities" issued by the Emerging Issues Task Force of the Financial Accounting Standards Board ("FASB") in 1998, see Note 1 to the Consolidated Financial Statements.

For a discussion of Statement of Position 98-5, "Reporting on the Costs of Start-up Activities" ("SOP 98-5") issued by the Accounting Standards Executive Committee in April 1998, see Note 1 to the Consolidated Financial Statements.

For a discussion of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("Statement No. 133") issued by the FASB in June 1998, see Note 1 to the Consolidated Financial Statements.

MARKET RISKS

The Company is exposed to market risks, including changes in commodity prices and interest rates.

Commodity Price Risk The prices of energy commodities and transportation services are subject to fluctuations due to unpredictable factors including weather, transportation congestion and other factors which impact supply and demand. This commodity price risk is a consequence of purchasing energy at fixed and variable prices and providing deliveries at different tariff and variable prices. Costs associated with ownership and operation of production facilities are another component of this risk. The Company may use forward delivery agreements and option contracts for the purpose of hedging commodity price risk. Unrealized changes in the market value of these derivatives are deferred and recognized upon settlement along with the underlying hedged transaction. In addition, the Company believes its current rate design, including its

Optional Large Power Sales Rate, various special contracts and the PGA mechanism mitigate a portion of this risk.

Four option contracts entered into directly by the Company were outstanding at December 31, 1998, and had a market value at that date which approximated the option premiums paid by the Company.

Operating results are also influenced by the impact of market prices on the value of physical and derivative commodity contracts entered into by DETM as part of their agreement with the Company. Changes in the market value of all of these derivatives are recorded on a mark-to-market basis into income by DETM and can affect the Company's revenues from the DETM agreement.

DETM measures the market risk of physical and financial contracts entered into under the DETM Agreement using a value at risk model. The Company's proportionate share of the value at risk at December 31, 1998 was not material.

Market risk is managed subject to parameters established by the Board of Directors. A Risk Management Committee separate from the units that create these risks monitors compliance with the Company's policies and procedures. In addition, the Audit Committee of the Company's Board of Directors has oversight of the Risk Management Committee.

Interest rate risk The Company believes interest rate risks of the Company primarily relate to the use of short-term debt instruments and new long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company does utilize bank borrowings, commercial paper and line of credit facilities to meet short-term cash requirements. These short-term obligations are commonly refinanced with fixed rate bonds or notes when needed and when interest rates are considered favorable. The Company may enter into swap instruments to manage the interest rate risk associated with these debts, and one interest rate swap was outstanding as of December 31, 1998. The carrying amounts and fair values of the Company's fixed rate debt instruments are described in Note 10 to the Consolidated Financial Statements.

Item 8.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See index on page 60.

Item 9.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Part III

Part III is incorporated by reference from the Company's definitive proxy statement issued in connection with the 1999 Annual Meeting of Shareholders.

Certain information regarding executive officers is set forth in Part I.

Part IV Item 14.

EXHIBITS, FINANCIAL STATEMENT SCHEDULE AND REPORTS ON FORM 8-K

(a) Documents filed as part of this report:

1) Financial statement schedule - see index on page 60.

2) Exhibits - see index on page 92.

(b) Reports on Form 8-K:

1) Form 8-K filed November 13, 1998 – Item 5 – Other Events, and Item 7 – Exhibits, related to an Asset Purchase Agreement for the sale of the Company's interest in the Colstrip coal-fired generating plant.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUGET SOUND ENERGY, INC.

/s/ William S. Weaver
William S. Weaver
President and Chief Executive Officer
Date: March 4, 1999

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ William S. Weaver (William S. Weaver)	President, Chief Executive Officer and Director	March 4, 1999
/s/ R. R. Sonstelie (R. R. Sonstelie)	Chairman of the Board	March 4, 1999
/s/ James W. Eldredge (James W. Eldredge)	Corporate Secretary and Controller and Chief Accounting Officer	March 4, 1999
/s/ Douglas P. Beighle (Douglas P. Beighle)	Director	March 4, 1999
/s/ Charles W. Bingham (Charles W. Bingham)	Director	March 4, 1999
/s/ Phyllis J. Campbell (Phyllis J. Campbell)	Director	March 4, 1999
/s/ Donald J. Covey (Donald J. Covey)	Director	March 4, 1999
/s/ Robert Dryden (Robert Dryden)	Director	March 4, 1999
/s/ John D. Durbin (John D. Durbin)	Director	March 4, 1999
(John W. Ellis)	Director	March 4, 1999
/s/ Daniel J. Evans (Daniel J. Evans)	Director	March 4, 1999
/s/ Tomio Moriguchi (Tomio Moriguchi)	Director	March 4, 1999
/s/ Sally G. Narodick (Sally G. Narodick)	Director	March 4, 1999

PUGET SOUND ENERGY

REPORT OF MANAGEMENT

The accompanying consolidated financial statements of Puget Sound Energy, Inc. have been prepared under the direction of management, which is responsible for their integrity and objectivity. The statements have been prepared in accordance with generally accepted accounting principles and include amounts based on judgments and estimates by management where necessary. Management also prepared the other information in the Annual Report on Form 10-K and is responsible for its accuracy and consistency with the financial statements.

The Company maintains a system of internal control which, in management's opinion, provides reasonable assurance that assets are properly safeguarded and transactions are executed in accordance with management's authorization and properly recorded to produce reliable financial records and reports. The system of internal control provides for appropriate division of responsibility and is documented by written policy and updated as necessary. The Company's internal audit staff assesses the effectiveness and adequacy of the internal controls on a regular basis and recommends improvements when appropriate. Management considers the internal auditor's and independent auditor's recommendations concerning the Company's internal controls and takes steps to implement those that they believe are appropriate in the circumstances.

In addition, PricewaterhouseCoopers LLP, the independent auditors, have performed audit procedures deemed appropriate to obtain reasonable assurance about whether the financial statements are free of material misstatement.

The Board of Directors pursues its oversight role for the financial statements through the audit committee, which is composed solely of outside Directors. The audit committee meets regularly with management, the internal auditors and the independent auditors, jointly and separately, to review management's process of implementation and maintenance of internal accounting controls and auditing and financial reporting matters. The internal and independent auditors have unrestricted access to the audit committee.

/s/ William S. Weaver

William S. Weaver
President and Chief Executive Officer

/s/ Richard L. Hawley

Richard L. Hawley
Vice President and Chief Financial Officer

/s/ James W. Eldredge

James W. Eldredge
Corporate Secretary and Controller
(Chief Accounting Officer)

Report of

INDEPENDENT ACCOUNTANTS

To the Shareholders of Puget Sound Energy, Inc.

In our opinion, based upon our audits and the report of other auditors, the consolidated financial statements listed on page 60 of this Annual Report on Form 10-K present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries (the "Company") at December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles. In addition, in our opinion, the financial statement schedule listed on page 60 of this document presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. The consolidated financial statements give retroactive effect to the February 10, 1997 merger of Washington Energy Company ("WECo") and its principal subsidiary, Washington Natural Gas ("WNG"), in a transaction accounted for as a pooling of interests which is discussed in Note 1 to the consolidated financial statements. We did not audit the consolidated financial statements and the financial statement schedule of WECo and its principal subsidiary, WNG, which statements reflect total revenues of $426 million for the year ended December 31, 1996. Those financial statements and the financial statement schedule were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amounts included in the year ended December 31, 1996 for WECo and WNG, is based solely on the report of the other auditors. We conducted our audits of these financial statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

Seattle, Washington
February 11, 1999

Report of
INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of Washington Energy Company:

We have audited the consolidated statements of income, shareholders' earnings (deficit) reinvested in the business, premium on common stock and cash flows of Washington Energy Company (a Washington corporation) and subsidiaries for the year ended September 30, 1996, and the consolidated statements of income, shareholders' earnings reinvested in the business, premium on common stock and cash flows of Washington Natural Gas Company (a Washington corporation) and subsidiaries for the year ended September 30, 1996. These financial statements, which are not included in this Form 10-K, are the responsibility of the companies' management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

On February 10, 1997, Washington Energy Company and its principal subsidiary Washington Natural Gas Company, in a transaction accounted for as a pooling-of-interests, merged with Puget Sound Power and Light to form Puget Sound Energy.

In our opinion, the financial statements referred to above present fairly, in all material respects, the results of operations of Washington Energy Company and subsidiaries and of Washington Natural Gas Company and subsidiaries and their cash flows for the year ended September 30, 1996, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

Seattle, Washington,
October 31, 1996 (except with respect to the matter discussed
in the third paragraph above, for which the date is February 10, 1997)

CONSOLIDATED FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULE AND EXHIBITS

Covered by the Foregoing Report of Independent Accountants

All other schedules have been omitted because of the absence of the conditions under which they are required, or because the information required is included in the financial statements or the notes thereto.

Financial statements of the Company's subsidiaries are not filed herewith inasmuch as the assets, revenues, earnings and earnings reinvested in the business of the subsidiaries are not material in relation to those of the Company.

Consolidated Statements of

INCOME

(For Years Ended December 31; dollars in thousands, except per share amounts)	1998	1997	1996
Operating Revenues:			
Electric	$ 1,475,208	$ 1,231,424	$ 1,198,769
Gas	416,551	409,447	400,108
Other	15,581	36,031	50,402
Total operating revenues	1,907,340	1,676,902	1,649,279
Operating Expenses:			
Energy Costs:			
Purchased electricity	752,148	614,929	562,314
Residential Exchange	(55,562)	(71,970)	(103,154)
Purchased gas	175,805	179,287	177,719
Fuel	56,557	41,455	40,645
Utility operations and maintenance	237,835	251,390	243,085
Other operations and maintenance	7,614	21,256	32,234
Depreciation, depletion and amortization	165,587	161,865	144,206
Merger and related costs	—	55,789	4,835
Taxes other than federal income taxes	160,472	159,310	155,174
Federal income taxes	107,904	47,725	107,747
Total operating expenses	1,608,360	1,461,036	1,364,805
Operating Income	298,980	215,866	284,474
Other Income	9,192	28,066	1,593
Income Before Interest Charges	308,172	243,932	286,067
Interest Charges:			
AFUDC	(7,580)	(5,205)	(3,919)
Interest expense	146,140	123,439	122,635
Total interest charges	138,560	118,234	118,716
Income from Continuing Operations	169,612	125,698	167,351
Discontinued Operations:			
Loss from operations, net of tax	—	—	(1,386)
Loss on disposal, net of tax	—	(2,622)	(446)
Net Income	169,612	123,076	165,519
Less Preferred Stock Dividends Accrual	13,003	17,806	22,181
Preferred Stock Redemptions	—	471	—
Income for Common Stock	$ 156,609	$ 105,741	$ 143,338
Common Shares Outstanding Weighted Average	84,561	84,560	84,418
Basic and Diluted Earnings (Loss) Per Common Share:			
From continuing operations	$ 1.85	$ 1.28	$ 1.72
From discontinued operations	—	(0.03)	(0.02)
Basic and diluted earnings per common share	$ 1.85	$ 1.25	$ 1.70

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

Consolidated Balance Sheets

ASSETS

(At December 31; dollars in thousands)	1998	1997
Utility Plant:		
Electric plant	$ 3,827,685	$ 3,632,652
Gas plant	1,324,323	1,231,109
Less: Accumulated depreciation and amortization	1,721,096	1,613,300
Net utility plant	3,430,912	3,250,461
Other Property and Investments:		
Investment in Bonneville Exchange Power Contract	70,537	78,880
Other	192,863	200,764
Total other property and investments	263,400	279,644
Current Assets:		
Cash	25,278	7,759
Accounts receivable	201,980	158,927
Less: Allowance for doubtful accounts	(1,021)	(971)
Total accounts receivable	200,959	157,956
Unbilled revenues	126,740	122,831
Purchased gas receivable	5,492	—
Materials and supplies, at average cost	58,534	54,423
Prepayments and other	7,296	5,420
Total current assets	424,299	348,389
Long-Term Assets:		
Regulatory asset for deferred income taxes	241,406	258,430
PURPA buyout costs	221,802	215,000
Other	138,870	141,446
Total long-term assets	602,078	614,876
Total Assets	$ 4,720,689	$ 4,493,370

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

Consolidated Balance Sheets

CAPITALIZATION AND LIABILITIES

(At December 31; dollars in thousands)	1998	1997
Capitalization:		
(See "Consolidated Statements of Capitalization"):		
Common equity	$ 1,352,680	$ 1,358,077
Preferred stock not subject to mandatory redemption	95,075	95,488
Preferred stock subject to mandatory redemption	73,162	78,134
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	100,000	100,000
Long-term debt	1,474,748	1,411,707
Total capitalization	3,095,665	3,043,406
Current Liabilities:		
Accounts payable	167,691	124,899
Short-term debt	450,905	372,538
Current maturities of long-term debt	107,000	51,000
Purchased gas liability	—	876
Accrued expenses:		
Taxes	72,883	73,636
Salaries and wages	16,053	15,326
Interest	39,062	27,704
Other	23,008	24,847
Total current liabilities	876,602	690,826
Deferred Income Taxes	628,554	629,018
Other Deferred Credits	119,868	130,120
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 4,720,689	$ 4,493,370

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

Consolidated Statements of

CAPITALIZATION

(At December 31; dollars in thousands)	1998	1997
Common Equity:		
Common stock ($10 stated value) - 150,000,000 shares authorized, 84,560,561 and 84,560,645 shares outstanding	$ 845,606	$ 845,606
Additional paid-in capital	450,724	450,845
Earnings reinvested in the business	47,548	46,672
Accumulated other comprehensive income - net	8,802	14,954
Total common equity	1,352,680	1,358,077
Preferred Stock Not Subject to Mandatory Redemption - cumulative, $25 par value:*		
Adjustable Rate, Series B - 2,000,000 shares authorized, 203,006 and 219,506 shares outstanding	5,075	5,488
7.45% series II - 2,400,000 shares authorized and outstanding	60,000	60,000
8.50% series III - 1,200,000 shares authorized and outstanding	30,000	30,000
Total preferred stock not subject to mandatory redemption	95,075	95,488
Preferred Stock Subject To Mandatory Redemption - cumulative, $100 par value:*		
4.84% series - 150,000 shares authorized, 14,808 shares outstanding	1,481	1,481
4.70% series - 150,000 shares authorized, 4,311 shares outstanding	431	431
8% series - 150,000 shares authorized, -0- and 12,224 shares outstanding	—	1,222
7.75% series – 750,000 shares authorized, 712,500 and 750,000 shares outstanding	71,250	75,000
Total preferred stock subject to mandatory redemption	73,162	78,134
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	100,000	100,000
Long-Term Debt:		
First mortgage bonds and senior notes	1,420,000	1,301,000
Pollution control revenue bonds:		
Revenue refunding 1991 series, due 2021	50,900	50,900
Revenue refunding 1992 series, due 2022	87,500	87,500
Revenue refunding 1993 series, due 2020	23,460	23,460
Other notes	12	17
Unamortized discount - net of premium	(124)	(170)
Long-term debt due within one year	(107,000)	(51,000)
Total long-term debt excluding current maturities	1,474,748	1,411,707
Total Capitalization	$ 3,095,665	$ 3,043,406

** 13,000,000 shares authorized for $25 par value preferred stock and 3,000,000 shares authorized for $100 par value preferred stock.*

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

Consolidated Statements of

EARNINGS REINVESTED

(For Years Ended December 31; dollars in thousands, except per share amounts)	1998	1997	1996
Balance at Beginning of Year	$ 46,672	$ 86,355	$ 84,254
Net Income	169,612	123,076	165,519
Adjustment to conform fiscal year of WECo	—	10,835	—
Total	216,284	220,266	249,773
Deductions:			
Dividends declared:			
Preferred stock:			
Adjustable Rate Series B	272	2,010	2,716
$1.86 per share on 7.45% series II	4,470	4,470	4,470
$2.13 per share on 8.50% series III	2,550	2,550	2,550
$4.84 per share on 4.84% series	72	192	232
$4.70 per share on 4.70% series	20	203	265
$8.00 per share on 8% series	25	122	218
$7.75 per share on 7.75% series	5,667	5,813	5,813
$1.97 per share on 7.875% series	—	3,940	5,906
Common Stock	155,591	150,591	141,248
Preferred stock redemptions	69	3,703	—
Total deductions	168,736	173,594	163,418
Balance at End of Year	$ 47,548	$ 46,672	$ 86,355
Dividends Declared Per Common Share	$ 1.84	$ 1.78	$ 1.67

Consolidated Statements of

COMPREHENSIVE INCOME

(For Years Ended December 31; dollars in thousands)	1998	1997	1996
Net Income	$ 169,612	$ 123,076	$ 165,519
Other comprehensive income, net of tax:			
Unrealized holding gains (losses) on available for sale securities	(6,152)	14,954	—
Comprehensive Income	$ 163,460	$ 138,030	$ 165,519

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

Consolidated Statements of

CASH FLOW

(For Years Ended December 31; dollars in thousands)	1998	1997	1996
Operating Activities:			
Income from continuing operations	$ 169,612	$ 125,698	$ 167,351
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation and amortization	165,587	161,865	144,206
Deferred income taxes and tax credits - net	16,560	27,422	6,842
PRAM accrued revenues - net	—	40,777	74,326
Pretax write-down and equity in undistributed losses of unconsolidated affiliate	—	4,044	961
PURPA buyout costs	—	(215,000)	—
Other	(14,792)	43,286	(21,918)
Change in certain current assets and liabilities	(22,692)	(58,394)	27,809
Net cash provided by operating activities	314,275	129,698	399,577
Investing Activities:			
Construction expenditures - excluding equity AFUDC	(335,471)	(257,900)	(205,050)
Energy conservation expenditures	(6,745)	(4,864)	(6,683)
Cash received from sale of conservation assets - net	—	34,372	—
Proceeds from property sales	6,877	7,013	34,000
Other	1,967	17,703	(7,384)
Net cash used by investing activities	(333,372)	(203,676)	(185,117)
Financing Activities:			
Increase (decrease) in short-term debt	78,367	85,975	(30,921)
Dividends paid	(168,667)	(169,892)	(163,418)
Issuance of common and preferred stock	—	65	3,686
Issuance of company obligated, mandatorily redeemable preferred securities	—	100,000	—
Redemption of preferred stock	(5,454)	(128,747)	(1,200)
Issuance of bonds	200,000	300,000	34,470
Redemption of bonds and notes	(81,004)	(102,844)	(72,612)
Other	13,374	(4,572)	(558)
Net cash provided (used) by financing activities	36,616	79,985	(230,553)
Increase (Decrease) in cash from continuing operations	17,519	6,007	(16,093)
Decrease in cash from discontinued operations:			
Operating activities	—	—	(1,386)
Investing activities	—	(2,622)	—
Net Increase (Decrease) in Cash	17,519	3,385	(17,479)
Cash at Beginning of Year	7,759	4,335	21,814
Adjustment to conform fiscal year of WECo	—	39	—
Cash at End of Year	$ 25,278	$ 7,759	$ 4,335

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

NOTES

To Consolidated Financial Statements

NOTE 1.

Summary of Significant Accounting Policies

Basis of Presentation Puget Sound Energy, Inc., formerly Puget Sound Power & Light Company ("the Company"), is an investor-owned public utility incorporated in the State of Washington furnishing electric, and since February 10, 1997, gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region of Washington state. On February 10, 1997, the Company completed a merger ("the Merger") with Washington Energy Company ("WECo") and its principal subsidiary, Washington Natural Gas Company ("WNG"). The change of the Company's name was effective with the merger. Herein, the Company refers to the combined entity; Puget Power and WECo refer to the individual entities.

The merger has been structured as a tax-free exchange of shares, and is accounted for as a pooling of interests for financial statement purposes. Accordingly, the consolidated financial statements have been retroactively restated to include the results of operations, financial position and cash flows of WECo and WNG for all periods prior to consummation of the merger. Financial information prior to January 1, 1997, contained herein reflects fiscal years ended December 31 for Puget Power and September 30 for WECo. Certain reclassifications have been made to the 1997 and 1996 financial statements to conform to the 1998 presentation with no effect on consolidated net income, total assets or common equity.

The consolidated financial statements include the accounts of the Company and all its significant wholly-owned subsidiaries, after elimination of all significant intercompany items and transactions. One immaterial subsidiary is stated on an equity basis.

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 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.

Utility Plant The costs of additions to utility plant, including renewals and betterments, are capitalized at original cost. Costs include indirect costs such as engineering, supervision, certain taxes and pension and other employee benefits, and an allowance for funds used during construction. Replacements of minor items of property are included in maintenance expense. The original cost of operating property together with removal cost, less salvage, is charged to accumulated depreciation when the property is retired and removed from service.

Regulatory Assets & Agreements The Company prepares its financial statements in accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("Statement No. 71"). Statement No. 71 requires the Company to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. Accounting under Statement No. 71 is appropriate as long as: rates are established by or subject to approval by independent, third-party regulators; rates are designed to recover the specific enterprise's cost-of-service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In applying Statement No. 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with Statement No. 71, the Company capitalizes certain costs in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

Net regulatory assets and liabilities at December 31, 1998 and 1997, included the following:

(Dollars in Millions)	1998	1997
Deferred income taxes	$ 241.4	$ 258.4
PURPA buyout costs	221.8	215.0
Investment in BEP Exchange Contract	70.5	78.9
Unamortized energy conservation charges	7.1	6.9
Storm damage costs	34.6	33.4
Various other costs	63.0	68.2
Deferred gains on property sales	(17.2)	(17.5)
Total	$ 621.2	$ 643.3

If the Company, at some point in the future, determines that all or a portion of the utility operations no longer meets the criteria for continued application of Statement No. 71, the Company would be required to adopt the provisions of Statement of Financial Accounting Standards No. 101, "Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71" ("Statement No. 101"). Adoption of Statement No. 101 would require the Company to write off the regulatory assets and liabilities related to those operations not meeting Statement No. 71 requirements. Discontinuation of Statement No. 71 could have a material impact on the Company's financial statements.

The Emerging Issues Task Force ("EITF") of the Financial Accounting Standards Board ("FASB") met in May and July of 1997 to address the issues of when an entity should discontinue the application of Statement No. 71, and how Statement No. 101 should be applied to a portion of an entity subject to a transition-to-competition plan. As a result of these meetings, a consensus was reached that Statement No. 71 should be discontinued at a date no later than when the details of the transition-to-competition plan for all or a portion of the entity subject to such plan are known. Additionally, the EITF reached a consensus that stranded costs which are to be recovered through cash flows derived from another portion of the entity which continues to apply Statement No. 71 should not be written off; rather, they should be considered regulatory assets of the segment which will continue to apply Statement No. 71.

The Company's financial statements continue to apply Statement No. 71 for regulated operations. Although discussions with regulatory authorities regarding retail competition have occurred and are expected to continue, no final transition to competition plans for the Company's regulated operations have yet been adopted or proposed.

The Company, in prior years, incurred costs associated with its 5% interest in a now-terminated nuclear generating project (identified herein as "Investment in Bonneville Exchange Power ("BEP")"). Under terms of a settlement agreement with the Bonneville Power Administration ("BPA"), which settled claims of the Company relating to construction delays associated with that project, the Company is receiving, over 30.5 years, power from the federal power system resources marketed by BPA. Approximately two-thirds of the Company's investment in BEP is included in rate base and amortized on a straight-line basis over the life of the contract (amortization is included in "Purchased and interchanged power"). The remainder of the Company's investment is being recovered in rates over ten years, without a return during the recovery period (the related amortization is included in "Depreciation and Amortization", pursuant to a FERC accounting order).

The Company has recorded a regulatory asset for $215 million related to the buyout of a gas sales contract of a non-utility generator. A Washington Commission accounting order approved the payment for deferral and collection in rates over the remaining life of the energy supply contract. Under terms of the order, the Company is allowed to accrue as an additional regulatory asset one-half the carrying costs of the deferred balance over the first five years.

The Company also has agreements under which ConneXt, a wholly owned subsidiary of the Company performs certain billing and customer information technology functions. Under an accounting order approved by the Washington Commission, the Company records payments to ConneXt as if such costs were paid to third-party providers and these costs will be reviewed in a future rate filing.

Operating Revenues Operating revenues are recorded on the basis of service rendered, which includes estimated unbilled revenue and, prior to October 1, 1996, revenue accrued under the Periodic Rate Adjustment Mechanism ("PRAM").

Energy Conservation The Company accumulates energy conservation expenditures which are included in rate base and amortized to expense as prescribed by the Washington Commission.

In June 1995, the Company sold approximately $202.5 million of its investment in customer-owned energy conservation measures to a grantor trust which, in turn, issued securities backed by a Washington state statute enacted in 1994. The Company sold an additional investment of $35.2 million in customer-owned energy conservation measures in August 1997. The proceeds of the sales were used to pay down short-term debt. The Company recognized no gain or loss on the sales.

Self-Insurance The Company currently has no insurance coverage for storm damage and is self-insured for a portion of the risk associated with comprehensive liability, industrial accidents and catastrophic property losses. With approval of the Washington Commission, the Company is able to defer for collection in future rates certain uninsured storm damage costs associated with major storms.

Depreciation and Amortization For financial statement purposes, the Company provides for depreciation on a straight-line basis. The depreciation of automobiles, trucks, power operated equipment and tools is allocated to asset and expense accounts based on usage. The annual depreciation provision stated as a percent of average original cost of depreciable electric utility plant was 3.0% in 1998, 1997 and 1996 and for depreciable gas utility plant was 3.4% in 1998 and 1997 and 3.6% in 1996.

Federal Income Taxes The Company normalizes, with the approval of the Washington Commission, certain items. Deferred taxes have been determined under Statement of Financial Accounting Standards No. 109. Investment tax credits are deferred and amortized based on the average useful life of the related property in accordance with regulatory and income tax requirements. (See Note 13.)

Allowance for Funds Used During Construction The Allowance for Funds Used During Construction ("AFUDC") represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending principally upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant and is credited as a non-cash item to other income and interest charges currently. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rate allowed by the Washington Commission for gas utility plant additions was 9.15% in 1998 and 1997 and 9.03% in 1996. The allowed AFUDC rate on electric utility plant was 8.94% during the same period. To the extent amounts calculated using this rate exceed the AFUDC calculated using the Federal Energy Regulatory Commission ("FERC") formula, the Company capitalizes the excess as a deferred asset, crediting miscellaneous income. The amounts included in income were: $3,409,000 for 1998, $2,704,000 for 1997 and $2,112,000 for 1996. The deferred asset is being amortized over the average useful life of the Company's non-project utility plant.

Periodic Rate Adjustment Mechanism In April 1991, the Washington Commission issued an order establishing a PRAM designed to operate as an interim rate adjustment mechanism between electric general rate cases. Under the PRAM, Puget Power was allowed to request annual rate adjustments, on a prospective basis, to reflect changes in certain costs as set forth in the PRAM order. Also, under terms of the order, recovery of certain costs was decoupled from levels of electricity sales.

Rates established for the PRAM period were subject to future adjustment based on actual customer growth and variations in certain costs, principally those affected by hydro and weather conditions. To the extent revenue billed to customers varied from amounts allowed under the methodology established in the PRAM order, the difference was accumulated, without interest, for rate recovery which was then established in the next PRAM hearing. In its September 22, 1995, order, the Washington Commission approved Puget Power's last PRAM filing and the recovery of $71.2 million over the period October 1, 1995, through September 30, 1996. In addition to approval of the rate adjustment, the Commission also agreed, pursuant to a negotiated settlement, to discontinue the PRAM on September 30, 1996, the end of the last PRAM period. PRAM accrued revenues of $40.5 million, recorded at December 31, 1996, were recovered in the first quarter of 1997. Over-collection of PRAM revenues was refunded to customers in the second quarter of 1997.

With the discontinuance of the PRAM, the Company no longer has a rate adjustment mechanism to adjust for changes in energy or fuel costs or variances in hydro and weather conditions. These variances may now significantly influence earnings.

PGA Mechanism Differences between the actual cost of the Company's gas supplies and that currently allowed by the Washington Commission are deferred and recovered or repaid through the purchased gas adjustment ("PGA") mechanism.

On June 25, 1998, the Company received approval from the Washington Commission to begin a new performance-based mechanism for strengthening its gas-supply purchasing and gas-storage practices. The PGA Incentive Mechanism, which encourages competitive gas purchasing and management of pipeline and storage-capacity, became effective July 1, 1998. Incentive gains and losses from the three-year program are shared between customers and shareholders. After the first $0.5 million, which is allocated to customers, gains and losses are shared 40%/60% between the Company and customers up to $26.5 million and 33%/67% thereafter. Gains or losses are determined relative to a weighted average index which is reflective of the Company's gas supply and transportation contract costs. The Company's share of incentive gains under the PGA Incentive Mechanism in 1998 were approximately $1.1 million while customers received approximately $2.0 million.

Off-System Sales and Capacity Release The Company has been selling excess gas supplies and entering into gas supply exchanges with third parties outside of its distribution area since 1992. The Company began releasing to third parties excess interstate gas pipeline capacity and gas storage rights on a short-term basis in 1993 and 1994, respectively. The Company contracts for firm gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for gas for space heating by its firm customers. Due to the variability in weather and other factors, however, the Company holds contractual rights to gas supplies and transportation and storage capacity in excess of its immediate requirements to serve firm customers on its distribution system for much of the year which, therefore, are available for third-party gas sales, exchanges and capacity releases. The net proceeds from such activities are accounted for as reductions in the cost of purchased gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, the Company does not reflect sales revenue or associated cost of sales for these transactions in its income statement. The net proceeds from these activities were $22,071,881, $16,759,000 and $10,711,000 for 1998, 1997 and 1996, respectively.

Risk Management and Energy Trading The Company's energy related businesses are exposed to risks related to changes in commodity prices. As part of its business, the Company markets power to other utilities and power marketers by entering into contracts to purchase or supply electric energy or natural gas at specified delivery points and at specified future delivery dates. The Company's energy trading function manages the Company's core electric and gas supply portfolios as well as non-core incremental energy supply trading activities.

The Company enters into futures and options for the purpose of hedging commodity price picks. Gains or losses on these derivatives are deferred and recognized upon settlement along with the underlying sales or purchase contract. The Company has established policies and procedures to manage these risks. A Risk Management Committee separate from the units that create these risks monitors compliance with the Company's policies and procedures. In addition, the Audit Committee of the Company's Board of Directors has oversight of the Risk Management Committee.

Other Debt premium, discount and expenses are amortized over the life of the related debt. The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

In June 1997, the FASB issued Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income" ("Statement No. 130"), which establishes rules for reporting and displaying comprehensive income and its components. In June 1997, the FASB issued Statement of Financial Accounting Standards No. 131, "Disclosures about Segments of an Enterprise and Related Information" ("Statement No. 131"), which established requirements that companies report certain information about operating segments. In February 1998, the FASB issued Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" ("Statement No. 132"), which standardizes the disclosure requirements for pensions and other postretirement benefits. The Company adopted these statements in 1998 which resulted in additional financial disclosures but no impact on the Company's financial position or results of operations.

During 1998, the EITF of the FASB released Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" ("EITF 98-10"). EITF 98-10 addresses accounting for the purchase and sale of energy trading contracts. The conclusion reached by the EITF was that such energy trading contracts should be recorded at fair value with the mark-to-market gains or losses recorded in current earnings. EITF 98-10 is effective for fiscal years beginning after December 15, 1998. The Company does not consider its current operations to meet the definition of trading activities as described by EITF 98-10, other than the activities entered into on the Company's behalf through the contract with DETM. These activities are currently accounted for using fair value and mark-to-market accounting. Accordingly, the Company has concluded that the adoption of EITF 98-10 will not have a material impact on the Company's financial position or results of operations.

In April 1998, the Accounting Standards Executive Committee issued Statement of Position 98-5, "Reporting on the Costs of Start-Up Activities" ("SOP 98-5"). SOP 98-5 is effective for fiscal years beginning after December 15, 1998. SOP 98-5 provides guidance on the financial reporting of start-up costs and organization costs. It requires costs of start-up activities and organization costs to be expensed as incurred. The Company has not yet determined the impact that the adoption of SOP 98-5 will have on its financial position or results of operations.

In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("Statement No. 133"). Statement No. 133 is effective for the fiscal year ending December 31, 2000. Statement No. 133 requires that all derivative instruments be recorded on the balance sheet at their fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, the type of hedge transaction. The Company has not yet determined the impact that the adoption of Statement No. 133 will have on its financial statements or the timing of adoption.

Earnings Per Common Share During 1997, the Company adopted Statement of Financial Accounting Standards No. 128, "Earnings per Share" ("Statement No. 128"). As required under Statement No. 128, earnings per share data have been restated for all prior periods presented.

Basic earnings per common share have been computed based on weighted average common shares outstanding of 84,561,000, 84,560,000 and 84,418,000 for 1998, 1997 and 1996, respectively. Diluted earnings per common share have been computed based on weighted average common shares outstanding of 84,768,000, 84,628,000 and 84,449,000 for 1998, 1997 and 1996, respectively, which include the dilutive effect of securities related to employee compensation plans.

NOTE 2.

Property Plant and Equipment

December 31 (dollars in thousands)	1998	1997
Electric and gas utility plant classified by Prescribed accounts at original cost:		
Distribution plant	$ 2,794,906	$ 2,674,234
Production plant	943,808	939,211
Transmission plant	641,526	625,779
General plant	375,612	333,140
Construction work in progress	266,242	123,690
Completed work not classified	—	58,216
Intangible plant	99,776	78,491
Underground storage	16,307	16,277
Plant held for future use	9,016	10,263
Other	4,815	4,460
Total electric and gas utility plant	$ 5,152,008	$ 4,863,761

NOTE 3.

Capital Stock

	Preferred Stock: Not Subject to Mandatory Redemption $25 Par Value	Preferred Stock: Subject to Mandatory Redemption $100 Par Value	Common Stock Without Par Value ($10 Stated Value)
Shares outstanding January 1, 1996	8,600,000	890,395	84,340,755
Issued to Shareholders Under the Stock Purchase and Dividend Reinvestment Plan:			
1996	—	—	148,417
1997	—	—	33,930
Issued Pursuant to Employee Compensation Plans:			
1996	—	—	21,886
1997	—	—	17,063
Issued Pursuant to Directors' Stock Bonus Plan:			
1996	—	—	187
Acquired for Sinking Fund:			
1996	—	(12,000)	—
1997	—	(12,050)	—
1998	—	(49,500)	—
Called for Redemption and Canceled:			
1997	(4,780,494)	(85,002)	—
1998	(16,500)	(224)	—
Fractional Share Redemptions in Connection with Merger Exchange:			
1997	—	—	(1,593)
1998	—	—	(84)
Shares outstanding December 31, 1998	3,803,006	731,619	84,560,561

See "Consolidated Statements of Capitalization" for details on specific series.

On January 15, 1991, the Board of Directors declared a dividend of one preference share purchase right (a "Right") on each outstanding common share of the Company. The dividend was distributed on January 25, 1991, to shareholders of record on that date. The Rights will be exercisable only if a person or group acquires 10 percent or more of the Company's common stock or announces a tender offer which, if consummated, would result in ownership by a person or group of 10 percent or more of the common stock. Each Right entitles the registered holder to purchase from the Company one one-thousandth of a share of Preference Stock, $50 par value per share, at an exercise price of $45, subject to adjustments. The description and terms of the Rights are set forth in a Rights Agreement between the Company and The Bank of New York, as Rights Agent. The Rights expire on January 25, 2001, unless earlier redeemed by the Company.

The weighted average dividend rate for the Adjustable Rate Cumulative Preferred Stock ("ARPS"), Series B ($25 par value) was 4.83% for 1998, 5.61% for 1997 and 5.49% for 1996. The Company reacquired 16,500 shares of ARPS Series B through open-market purchases during 1998 and redeemed the remaining ARPS on February 2, 1999 at $25 par plus accrued dividends through February 2, 1999.

The 8.50% and 7.45% Series Preferred may be redeemed at par on or after September 1, 1999, and November 1, 2003, respectively.

NOTE 4.

Preferred Stock Subject to Mandatory Redemption

The Company is required to deposit funds annually in a sinking fund sufficient to redeem the following number of shares of each series of preferred stock at $100 per share plus accrued dividends: 4.84% Series and 4.70% Series, 3,000 shares each and 7.75% Series, 37,500 shares. All previous sinking fund requirements have been satisfied. At December 31, 1998, there were 36,192 shares of the 4.84% Series and 52,689 shares of the 4.70% Series acquired by the Company and available for future sinking fund requirements. Upon involuntary liquidation, all preferred shares are entitled to their par value plus accrued dividends.

The preferred stock subject to mandatory redemption may also be redeemed by the Company at the following redemption prices per share plus accrued dividends: 4.84% Series, $102 and 4.70% Series, $101. The 7.75% Series may be redeemed by the Company, subject to certain restrictions, at $104.65 per share plus accrued dividends through February 15, 1999, and at per share amounts which decline annually to a price of $100 after February 15, 2007.

On February 15, 1998, the Company redeemed all outstanding shares of the 8% Series, $100 par value Preferred including 12,000 shares for the sinking fund at par and 224 shares at $101.00 per share.

NOTE 5.

Company-Obligated, Mandatorily Redeemable Preferred Securities

In 1997, the Company formed Puget Sound Energy Capital Trust I (the "Trust") for the sole purpose of issuing and selling common and preferred securities ("Trust Securities"). The proceeds from the sale of Trust Securities were used to purchase Junior Subordinated Debentures ("Debentures") from the Company. The Debentures are the sole assets of the Trust and the Company owns all common securities of the Trust.

The Debentures have an interest rate of 8.231% and a stated maturity date of June 1, 2027. The Trust Securities are subject to mandatory redemption at par on the stated maturity date of the Debentures. The Trust Securities may be redeemed earlier, under certain conditions, at the option of the Company. Dividends relating to preferred securities are included in interest expense.

NOTE 6.

Additional Paid-in Capital

(DOLLARS IN THOUSANDS)	1998	1997	1996
Balance at beginning of year	$ 450,845	$ 446,910	$ 444,928
Excess of proceeds over stated values of common stock issued	—	428	2,022
Par value over cost of reacquired preferred stock	—	471	—
Retained earnings adjustment for preferred redemption	—	3,036	—
Issue costs and other expenses	(121)	—	(40)
Balance at end of year	$ 450,724	$ 450,845	$ 446,910

NOTE 7.

Earnings Reinvested in the Business

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in the Company's Articles of Incorporation and Mortgage Indentures. Under the most restrictive covenants, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $183 million at December 31, 1998.

The adjustments made to the carrying value of costs associated with the terminated generating projects and Bonneville Exchange Power as a result of Statement No. 90, adjustments made as a result of Statement No. 121 and the disallowance of certain terminated generating project costs by the Washington Commission do not impact the amount of earnings reinvested in the business for purposes of payment of dividends on common stock under the terms of the Company's Articles and Mortgage Indentures. (See Note 1.)

NOTE 8.

Long-Term Debt

First Mortgage Bonds and Senior Notes
(AT DECEMBER 31; DOLLARS IN THOUSANDS):

SERIES	DUE	1998	1997	SERIES	DUE	1998	1997
6.17%	1998	—	10,000	7.70%	2004	50,000	50,000
5.70%	1998	—	5,000	7.80%	2004	30,000	30,000
8.25%	1998	—	11,000	6.92 & 6.93%	2005	31,000	31,000
8.83%	1998	—	25,000	6.58%	2006	10,000	10,000
6.50%	1999	16,500	16,500	8.06%	2006	46,000	46,000
6.65%	1999	10,000	10,000	8.14%	2006	25,000	25,000
6.41%	1999	20,500	20,500	7.02 & 7.04%	2007	25,000	25,000
7.08%	1999	10,000	10,000	7.75%	2007	100,000	100,000
7.25%	1999	50,000	50,000	8.40%	2007	10,000	10,000
6.61%	2000	10,000	10,000	6.51 & 6.53%	2008	4,500	4,500
9.60%	2000	25,000	25,000	6.61 & 6.62%	2009	8,000	8,000
8.51 - 8.55%	2001	19,000	19,000	7.12%	2010	7,000	7,000
9.14%	2001	—	30,000	8.59%	2012	5,000	5,000
7.53 - 7.91%	2002	30,000	30,000	8.20%	2012	30,000	30,000
7.85%	2002	30,000	30,000	6.83% & 6.90%	2013	13,000	13,000
7.07%	2002	27,000	27,000	7.35 & 7.36%	2015	12,000	12,000
7.15%	2002	5,000	5,000	6.74%	2018	200,000	—
7.625%	2002	25,000	25,000	9.57%	2020	25,000	25,000
6.23 - 6.31%	2003	28,000	28,000	8.25 - 8.40%	2022	35,000	35,000
7.02%	2003	30,000	30,000	7.19%	2023	13,000	13,000
6.20%	2003	3,000	3,000	7.35%	2024	55,000	55,000
6.40%	2003	11,000	11,000	7.15 & 7.20%	2025	17,000	17,000
6.07 & 6.10%	2004	18,500	18,500	7.02%	2027	300,000	300,000
Total						$1,420,000	$1,301,000

On June 15, 1998, the Company issued $200 million principal amount of 6.74% Senior Medium Term Notes, Series A. The Notes are due June 15, 2018.

On June 22, 1998, the Company redeemed $30 million principal amount of First Mortgage Bonds, 9.14% Series due June 21, 2001, at a redemption price of 100%.

In September 1998, the Company filed a shelf-registration statement for the offering on a delayed or continuous basis of up to $500 million principal amount of Senior Notes secured by a pledge of First Mortgage Bonds.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and gas mortgage indentures.

Pollution Control Bonds The Company has outstanding three series of Pollution Control Bonds. Amounts outstanding were borrowed from the City of Forsyth, Montana ("the City"). The City obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 and 4.

Each series of bonds are collateralized by a pledge of the Company's First Mortgage Bonds, the terms of which match those of the Pollution Control Bonds. No payment is due with respect to the related series of First Mortgage Bonds so long as payment is made on the Pollution Control Bonds. Interest rates for the 1992 and 1993 series are 6.80% and 5.875%, respectively. The 1991 series consists of $27.5 million principal amount bearing interest at 7.05% and $23.4 million principal amount bearing interest at 7.25%.

Long-Term Debt Maturities The principal amounts of long-term debt maturities for the next five years are as follows:

(Dollars in Thousands)	
Maturities of long-term debt	
1999	$ 107,000
2000	$ 35,000
2001	$ 19,000
2002	$ 117,000
2003	$ 72,000

NOTE 9.

Short-Term Debt and Other Financing Arrangements

At December 31, 1998, the Company had short-term borrowing arrangements which included a $375 million line of credit with thirteen banks. The agreement provides the Company with the ability to borrow at different interest rate options and includes variable fee levels. The options are: (1) the higher of the prime rate or the Federal Funds rate plus 1/2 of 1 percent or (2) the Eurodollar rate plus .25 percent. The current availability fee is .08 percent per annum on the unused loan commitment.

In addition, the Company has agreements with several banks to borrow on an uncommitted, as available, basis at money-market rates quoted by the banks. There are no costs, other than interest, for these arrangements. The Company also uses commercial paper to fund its short-term borrowing requirements.

At December 31: (Dollars in Thousands)	1998	1997	1996
Short-term borrowings outstanding:			
Commercial paper notes	$ 142,105	$ 124,538	$ 266,422
Bank line of credit borrowing	$ 25,000	$ 215,000	—
Uncommitted bank borrowings	$ 283,800	$ 33,000	$ 31,700
Weighted average interest rate	5.90%	6.88%	6.05%
Credit availability[1]	$ 375,000	$ 375,000	$ 426,500

1 Provides liquidity support for outstanding commercial paper and borrowing from credit line banks in the amount of $167.1 million, $339.5 million and $266.4 million for 1998, 1997 and 1996, respectively, effectively reducing the available borrowing capacity under these credit lines to $207.9 million, $35.5 million and $160.1 million, respectively.

The Company has, on occasion, entered into interest rate swap agreements to reduce the impact of changes in interest rates on portions of its floating-rate, short-term debt. The one agreement outstanding at December 31, 1998, effectively changes the Company's interest rate on outstanding commercial paper to 9.64% on a notional principal amount of $16.5 million expiring March 31, 2000.

NOTE 10.

Estimated Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments at December 31, 1998 and 1997:

(Dollars in Millions)	1998 Carrying Amount	1998 Fair Value	1997 Carrying Amount	1997 Fair Value
Financial Assets:				
Cash	$ 25.3	$ 25.3	$ 7.8	$ 7.8
Cabot common stock	$ 40.0	$ 40.0	$ 41.5	$ 41.5
Cabot preferred stock	$ 51.6	$ 51.6	$ 51.6	$ 51.6
Financial Liabilities:				
Short-term debt	$ 450.9	$ 450.9	$ 372.5	$ 372.5
Preferred stock subject to mandatory redemption	$ 73.2	$ 75.8	$ 78.1	$ 82.5
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	$ 100.0	$ 109.3	$ 100.0	$ 107.6
Long-term debt	$ 1,581.7	$ 1,686.0	$ 1,462.7	$ 1,547.3
Unrecognized financial instruments:				
Interest rate swaps	—	$ (1.3)	—	$ (1.2)

The fair value of outstanding bonds including current maturities is estimated based on quoted market prices.

The preferred stock subject to mandatory redemption and corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation is estimated based on dealer quotes.

The carrying value of short-term debt is considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of 3 months or less, is also considered to be a reasonable estimate of fair value.

The fair value of interest rate swaps (used for hedging purposes) is the estimated amount that the Company would receive or pay to terminate each swap agreement at the reporting date, taking into account current interest rates and the current credit-worthiness of all the parties to each swap.

Derivative instruments have been used by the Company on a limited basis. The Company has a policy that financial derivatives are to be used only to mitigate business risk and not for speculative purposes.

NOTE 11.

Supplementary Income Statement Information

(DOLLARS IN THOUSANDS)	1998	1997	1996
Taxes:			
Real estate and personal property	$ 40,422	$ 46,252	$ 43,762
State business	62,855	58,466	60,787
Municipal, occupational and other	48,090	45,252	43,681
Other	20,010	21,242	12,729
Total taxes	$ 171,377	$ 171,212	$ 160,959
Charged to:			
Operating expense	$ 160,472	$ 159,310	$ 155,174
Other accounts, including construction work in progress	10,905	11,902	5,785
Total taxes	$ 171,377	$ 171,212	$ 160,959

See "Consolidated Statements of Income" for maintenance and depreciation expense.

Advertising, research and development expenses and amortization of intangibles are not significant. The Company pays no royalties.

NOTE 12.

Leases

The Company treats all leases as operating leases for ratemaking purposes as required by the Washington Commission. Certain leases contain purchase options, renewal and escalation provisions. Capitalized leases are not material.

Rental and operating lease expense for the years ended December 31, 1998, 1997 and 1996, were approximately $17,798,000, $19,428,000 and $19,394,000, respectively. Payments due for the years ended December 31, 1998, 1997 and 1996, for the sublease of properties were approximately $1,242,000, $962,000 and $1,674,000, respectively.

Future minimum lease payments for noncancelable leases are approximately $14,562,000 for 1999, $14,762,000 for 2000, $13,501,000 for 2001, $13,040,000 for 2002, $10,833,000 for 2003 and in the aggregate, $7,137,000 thereafter. Future minimum sublease receipts for noncancelable subleases are $1,883,000 for 1999, $1,681,000 for 2000, $669,000 for 2001, $669,000 for 2002, $390,000 for 2003 and in the aggregate, $0 thereafter.

Note 13.

Federal Income Taxes

The details of federal income taxes ("FIT") are as follows:

(Dollars in Thousands)	1998	1997	1996
Charged to Operating Expense:			
Current	$ 90,696	$ 31,672	$ 111,989
Deferred - net	17,948	16,677	(3,058)
Deferred investment tax credits	(740)	(624)	(1,184)
Total FIT charged to operations	107,904	47,725	107,747
Charged to Miscellaneous Income:			
Current	5,601	16,709	(784)
Deferred - net	(648)	(1,902)	—
Total FIT charged to miscellaneous income	4,953	14,807	(784)
Credited to discontinued operations	—	(1,412)	(986)
Total FIT	$ 112,857	$ 61,120	$ 105,977

The following is a reconciliation of the difference between the amount of FIT computed by multiplying pre-tax book income by the statutory tax rate, and the amount of FIT in the Consolidated Statements of Income:

(Dollars in Thousands)	1998	1997	1996
FIT at the statutory rate	$ 98,864	$ 64,469	$ 95,024
Increase (Decrease):			
Depreciation expense deducted in the financial statements in excess of tax depreciation, net of depreciation treated as a temporary difference	7,756	7,019	6,603
AFUDC included in income in the financial statements but excluded from taxable income	(3,953)	(2,774)	(2,191)
Accelerated benefit on early retirement of depreciable assets	(1,241)	(805)	(1,105)
Investment tax credit amortization	(740)	(624)	(1,184)
Energy conservation expenditures - net	12,754	11,028	3,380
Conservation Settlement	—	(26,197)	—
Other - net	(583)	9,004	5,450
Total FIT	$ 112,857	$ 61,120	$ 105,977
Effective tax rate	40.0%	33.2%	39.0%

The following are the principal components of FIT as reported:

(Dollars in Thousands)	1998	1997	1996
Current FIT	$ 96,297	$ 48,381	$ 111,205
Deferred FIT - other:			
Conservation tax settlement	3,257	14,404	(759)
Periodic rate adjustment mechanism (PRAM)	107	(14,272)	(26,014)
Deferred taxes related to insurance reserves	(1,224)	(2,768)	(938)
Reversal of Statement No. 90 present value adjustments	255	408	552
Residential Purchase and Sale Agreement - net	3,441	(6,047)	(2,178)
Normalized tax benefits of the accelerated cost recovery system	20,118	22,575	23,407
Energy conservation program	(2,437)	5,101	(1,208)
Environmental remediation	(2,946)	(3,092)	1,148
WNP 3 tax settlement	(826)	21,360	—
Merger costs	42	(7,322)	—
Demand charges	3,273	(3,558)	—
Other	(5,760)	(12,014)	2,932
Total deferred FIT - other	17,300	14,775	(3,058)
Deferred investment tax credits - net of amortization	(740)	(624)	(1,184)
Credited to discontinued operations	—	(1,412)	(986)
Total FIT	$ 112,857	$ 61,120	$ 105,977

Deferred tax amounts shown above result from temporary differences for tax and financial statement purposes. Deferred tax provisions are not recorded in the income statement for certain temporary differences between tax and financial statement purposes because they are not allowed for ratemaking purposes.

The Company calculates its deferred tax assets and liabilities under Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("Statement No. 109"). Statement No. 109 requires recording deferred tax balances, at the currently enacted tax rate, for all temporary differences between the book and tax bases of assets and liabilities, including temporary differences for which no deferred taxes had been previously provided because of use of flow-through tax accounting for rate-making purposes. Because of prior and expected future ratemaking treatment for temporary differences for which flow-through tax accounting has been utilized, a regulatory asset for income taxes recoverable through future rates related to those differences has also been established. At December 31, 1998, the balance of this asset is $241.4 million.

The deferred tax liability at December 31, 1998 and 1997, is comprised of amounts related to the following types of temporary differences:

(Dollars in Thousands)	1998	1997
Utility plant	$ 567,642	$ 558,170
Investment in Cabot stock	13,435	13,435
Energy conservation charges	57,919	74,376
Contributions in aid of construction	(31,874)	(30,350)
Bonneville Exchange Power	26,513	30,240
Other	(5,081)	(16,853)
Total	$ 628,554	$ 629,018

The totals of $628.6 million and $629.0 million for 1998 and 1997 consist of deferred tax liabilities of $712.2 million and $712.0 million net of deferred tax assets of $83.6 million and $83.0 million, respectively.

Note 14.

Retirement Benefits

The Company has a defined benefit pension plan covering substantially all of its employees. Benefits are a function of both age and salary. Additionally, the Company maintains a non-qualified supplemental retirement plan for officers and certain director-level employees.

In addition to providing pension benefits, the Company provides certain health care and life insurance benefits for retired employees. These benefits are provided principally through an insurance company whose premiums are based on the benefits paid during the year.

Prior to March 1, 1997, the Company had separate defined benefit plans covering electric and gas employees. Prior to 1997, the plan covering electric employees had a measurement date of December 31 and the plan covering gas employees had a measurement date of September 30.

	Pension Benefits		Other Benefits	
(Dollars in Thousands)	1998	1997	1998	1997
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 325,063	$ 293,535	$ 27,433	$ 26,243
Service cost	8,550	8,268	229	216
Interest cost	22,862	21,412	1,985	1,895
Amendments	2,540	2,828	—	—
Actuarial (gain)/loss	15,272	3,532	1,896	884
Mergers, sales and closures	—	16,304	—	—
Benefits paid	(21,865)	(20,816)	(2,105)	(1,805)
Benefit obligation at end of year	$ 352,422	$ 325,063	$ 29,438	$ 27,433
Change in plan assets:				
Fair value of plan assets at beginning of year	$415,270	$354,634	$14,445	$13,718
Actual return on plan assets	67,544	80,548	570	803
Employer contribution	3,246	904	1,222	1,729
Benefits paid	(21,865)	(20,816)	(2,105)	(1,805)
Fair value of plan assets at end of year	$ 464,195	$ 415,270	$ 14,132	$ 14,445

(continued from previous page)

(Dollars in Thousands)	Pension Benefits 1998	1997	Other Benefits 1998	1997
Funded status	$ 111,773	$ 90,207	$ (15,306)	$ (12,988)
Unrecognized actuarial (gain)/loss	(133,189)	(117,841)	(1,532)	(3,822)
Unrecognized prior service cost	25,510	26,301	(463)	(497)
Unrecognized net initial (asset)/obligation	(7,563)	(8,794)	8,775	9,402
Net amount recognized	$ (3,469)	$ (10,127)	$ (8,526)	$ (7,905)
Amounts recognized on statement of financial position consist of:				
Prepaid benefit cost	$ 8,900	$ 2,238	$ (8,526)	$ (7,905)
Accrued benefit liability	(22,988)	(16,828)	—	—
Intangible asset	10,619	4,463	—	—
Net amount recognized	$ (3,469)	$ (10,127)	$ (8,526)	$ (7,905)

In accounting for pension and other benefits costs under the plans, the following weighted average actuarial assumptions were used:

	Pension Benefits 1998	1997	1996	Other Benefits 1998	1997	1996
Discount rate	7%	7.25-7.5%	7.5%	7%	7.25%	7.5%
Return on plan assets	9.75%	9%	8.5-9%	6-8.5%	6-8.5%	6-8.5%
Rate of compensation increase	5%	5%	5-5.5%	—	—	—
Medical Trend Rate	—	—	—	7.5%	7.5%	8%

(Dollars in Thousands)	Pension Benefits 1998	1997	1996	Other Benefits 1998	1997	1996
Components of net periodic benefit cost:						
Service cost	$ 8,550	$ 8,268	$ 6,958	$ 229	$ 216	$ 424
Interest cost	22,862	21,412	16,715	1,985	1,895	2,157
Expected return on plan assets	(33,744)	(27,997)	(20,944)	(867)	(821)	(687)
Amortization of prior service cost	3,330	2,247	1,258	(34)	(34)	32
Recognized net actuarial (gain)/loss	(3,180)	(1,144)	(3)	(97)	(204)	(230)
Amortization of transition (asset)/obligation	(1,230)	(1,095)	(420)	627	627	1,057
Plan curtailments, mergers	—	5,138	(1,613)	—	712	1,418
Net pension benefit cost under FASB Statement No. 87	(3,412)	6,829	1,951	1,843	2,391	4,171
Regulatory adjustment	1,263	1,263	1,263	—	—	—
Net periodic benefit cost	$ (2,149)	$ 8,092	$ 3,214	$ 1,843	$ 2,391	$ 4,171

The projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $27.7 million, $23.0 million and $0, respectively, as of December 31, 1998.

The assumed medical inflation rate is 7.5% in 1998 decreasing to 6% in 2003. A 1% change in the assumed medical inflation rate would have the following effects:

	1998		1997	
(DOLLARS IN THOUSANDS)	1% INCREASE	1% DECREASE	1% INCREASE	1% DECREASE
Effect on service and interest cost components	$ 690	$ (671)	$ 643	$ (625)
Effect on postretirement benefit obligation	$ 45	$ (44)	$ 42	$ (41)

In December 1995, in connection with the proposed merger with WECo, the Company offered to its employees a Voluntary Separation Plan. A total of 204 employees elected to participate in the Voluntary Separation Plan resulting in a curtailment gain for 1996 of $1.6 million under Statement of Financial Accounting Standards No. 88. In addition, curtailment losses under Statement No. 106 for 1997 of $4.7 million and 1996 of $1.4 million resulted from the 1995 Voluntary Separation Plan. Also in connection with the merger was a curtailment loss of $5.1 million in 1997 related to the supplemental retirement plans.

NOTE 15.

Employee Investment Plan & Employee Stock Purchase Plan

The Company has qualified Employee Investment Plans under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. The Company makes a monthly contribution equal to 100% on up to 4% of participant contributions and 50% on the next 4% of participant contributions which equates to a maximum contribution of 6% of eligible earnings. In addition, the Company contributes an amount equal to 1% of each participant's base pay at the end of the plan year.

The Company contributions to the Employee Investment Plan were $6,141,400, $5,068,100 and $4,102,000 for the years 1998, 1997 and 1996, respectively. The shareholders have authorized the issuance of up to 2,000,000 shares of common stock under the plan, of which 959,142 were issued through December 31, 1998. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

The Company also has an Employee Stock Purchase Plan which was approved by shareholders on May 19, 1997, and commenced July 1, 1997, under which options are granted to eligible employees who elect to participate in the plan on January 1st and July 1st of each year. Participants are allowed to exercise those options six months later to the extent of payroll deductions or cash payments accumulated during that six-month period. The option price under the plan is 90% of either the fair market value of the common stock at the grant date or the fair market value at the exercise date, whichever is less. The Company contributions to the Plan were $98,237 and $97,615 for 1998 and 1997, respectively.

NOTE 16.

Investment in Cabot Oil and Gas

In May 1994, the Company merged its oil and gas exploration and production subsidiary, Washington Energy Resources Company ("Resources"), with a wholly-owned subsidiary of Cabot Oil and Gas Corporation ("Cabot") in a tax-free exchange. At December 31, 1998, the Company owned 15.4% of Cabot's outstanding voting securities consisting of 2,133,000 shares of common stock and 1,134,000 shares of 6% convertible voting preferred stock, stated value $50. Prior to October 1, 1997, the Company's interest in Cabot's common stock was accounted for using the equity method because the Company, through its representation on Cabot's board of directors, had the ability to exercise significant influence over operating and financial policies of Cabot. Effective October 1, 1997, the Company discontinued equity-method accounting for Cabot and records its interest as an investment in stock because the Company no longer has representation on Cabot's board of directors. Equity in earnings (losses) from Cabot were $948,000 and ($619,000) for 1997 and 1996, respectively.

The investment in Cabot common stock has been classified as an available-for-sale security and is reported at its fair value, based on the closing price on the NYSE on December 31, 1998, of $31,995,000. The unrealized gain of $8,802,000 (net of deferred taxes of $4,739,000) is reported as a separate component of common equity. No fair value is readily available for the Cabot preferred stock as it is not publicly traded; however, its cost basis of $51,619,000 is believed to be a reasonable approximation of fair value at December 31, 1998.

See Note 17 regarding certain gas transportation, storage and other contractual arrangements of Resources that were excluded from the Cabot merger and retained by a subsidiary of the Company.

NOTE 17.

Commitments and Contingencies

Commitments – Electric For the twelve months ended December 31, 1998, approximately 20.1% of the Company's energy output was obtained at an average cost of approximately 11.5 mills per KWH through long-term contracts with several of the Washington public utility districts ("PUDs") owning hydro-electric projects on the Columbia River.

The purchase of power from the Columbia River projects is generally on a "cost-of-service" basis under which the Company pays a proportionate share of the annual cost of each project in direct proportion to the amount of power annually purchased by the Company from such project. Such payments are not contingent upon the projects being operable. These projects are financed through substantially level debt service payments, and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements or license requirements. The Company's share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the lives of the contracts.

As of December 31, 1998, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth in the following tabulation:

Project	Contract Exp. Date	License[1] Exp. Date	Bonds Outstanding 12/31/98[2] (Millions)	Company's Annual Amount Purchasable (Approximate) % of Output	Megawatt Capacity	Costs[3] (Millions)
Rock Island						
Original units	2012	2029	72.2	53.9	480	$39.1
Additional units	2012	2029	319.7	100.0		
Rocky Reach	2011	2006	227.2	38.9	505	20.8
Wells	2018	2012	172.5	31.3	261	9.0
Priest Rapids	2005	2005	171.9	8.0	72	2.1
Wanapum	2009	2005	194.7	10.8	98	3.2
Total					1,416	$74.2

1 The Company is unable to predict whether the licenses under the Federal Power Act will be renewed to the current licensees. The FERC has issued orders for Rocky Reach, Wells and Priest Rapids/Wanapum projects under Section 22 of the Federal Power Act, which affirm the Company's contractual rights to receive power under existing terms and conditions even if a new licensee is granted a license prior to expiration of the contract term.

2 The contracts for purchases initially were generally coextensive with the term of the PUD bonds associated with the project. Under the terms of some financings and refinancings, however, long-term bonds were sold to finance certain assets whose estimated useful lives extend beyond the expiration date of the power sales contracts. Of the total outstanding bonds sold for each project, the percentage of principal amount of bonds which mature beyond the contract expiration date are: 43.7% at Rock Island; 52.2% at Rocky Reach; 80.2% at Priest Rapids; and 47.8% at Wanapum.

3 The components of 1998 costs associated with the interest portion of debt service are: Rock Island, $23.6 million for all units; Rocky Reach, $4.8 million; Wells, $2.7 million; Priest Rapids, $0.9 million; and Wanapum, $1.2 million.

The Company's estimated payments for power purchases from the Columbia River projects are $82 million for 1999, $80 million for 2000, $80 million for 2001, $80 million for 2002, $78 million for 2003 and in the aggregate, $685 million thereafter through 2018.

The Company also has numerous long-term firm purchased power contracts with other utilities in the region. The Company is generally not obligated to make payments under these contracts unless power is delivered. The Company's estimated payments for firm power purchases from other utilities, excluding the Columbia River projects, are $151 million for 1999, $157 million for 2000, $151 million for 2001, $143 million for 2002, $132 million for 2003 and in the aggregate, $1.0 billion thereafter through 2037. These contracts have varying terms and may include escalation and termination provisions.

As required by the federal Public Utility Regulatory Policies Act ("PURPA"), the Company entered into long-term firm purchased power contracts with non-utility generators. The Company purchases the net electrical output of five significant projects at fixed and annually escalating prices which were intended to approximate the Company's avoided cost of new generation projected at the time these agreements were made. Principally, as a result of dramatic changes in natural gas price levels, the power purchase prices under these agreements are significantly above the current market price of power and, based upon projections of future market prices, are expected to remain well above market for the duration of the contracts. The Company's estimated payment under these five contracts are $280 million for 1999, $284 million for 2000, $308 million for 2001, $313 million for 2002, $318 million for 2003 and in the aggregate, $2.4 billion thereafter through 2012. If retail electric energy prices move to market levels as a result of electric industry restructuring, the above-market portion of these contract costs will become stranded costs which the Company plans to seek to continue to recover in rates.

The following table summarizes the Company's obligations for future power purchases.

(In Millions)	1999	2000	2001	2002	2003	2004 & Thereafter	Total
Columbia River Projects	$ 82	$ 80	$ 80	$ 80	$ 78	$ 685	$ 1,085
Other Utilities	151	157	151	143	132	1,000	1,734
Non-Utility Generators	280	284	308	313	318	2,400	3,903
Total	$ 513	$ 521	$ 539	$ 536	$ 528	$ 4,085	$ 6,722

Total purchased power contracts provided the Company with approximately 15.8 million, 15.6 million and 17.1 million MWH of firm energy at a cost of approximately $481.6 million, $464.5 million and $485.6 million for the years 1998, 1997 and 1996, respectively.

As part of its electric operations and in connection with the 1997 restructuring of the Tenaska Power Purchase Agreement the Company is obligated to deliver to Tenaska up to 48,000 MMBtu per day of natural gas for operation of Tenaska's cogeneration facility. This obligation continues for the remaining term of the agreement, provided that no deliveries are required during the month of May. The price paid by Tenaska for this gas is reflective of the daily price of gas at the U.S./Canada border near Sumas, Washington.

The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly-owned generating plants in service at December 31, 1998:

			Company's Share	
Project	Energy Source (Fuel)	Company's Ownership Share (%)	Plant in Service At Cost (Millions)	Accumulated Depreciation (Millions)
Centralia	Coal	7%	$ 26.7	$ 18.5
Colstrip 1 & 2	Coal	50%	187.1	106.6
Colstrip 3 & 4	Coal	25%	452.1	181.0

Financing for a participant's ownership share in the projects is provided for by such participant. The Company's share of related operating and maintenance expenses is included in corresponding accounts in the Consolidated Statements of Income. The Company and other joint owners of the Centralia Project are exploring alternative emission compliance options and project economics in light of compliance costs to meet the Phase II limits in the year 2000 and other regulations.

In November, 1998 the Company announced that it signed an agreement to sell its interest in the Colstrip plant, as well as associated transmission facilities to PP&L Global, Inc., of Fairfax, Virginia a subsidiary of PP&L Resources, Inc. The sales price is expected to be $549 million before taxes and expenses. The net book value of these assets and related regulatory assets is approximately $464 million. After consideration of taxes and other costs, the gain on the sale is expected to be approximately $37.6 million. The Company expects the Colstrip sale to close in the second half of 1999. Completion of the sale is contingent on receipt of acceptable regulatory treatment from the Washington Commission and the Federal Energy Regulatory Commission. The Company has also joined with the other owners of the Centralia project in offering for sale its ownership interest in the facility.

Certain purchase commitments have been made in connection with the Company's construction program.

Gas The Company has also entered into various firm supply, transportation and storage service contracts in order to assure adequate availability of gas supply for its firm customers. Many of these contracts, which have remaining terms from one to 25 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. Certain of the Company's firm gas supply agreements also obligate the Company to purchase a minimum annual quantity at market-based contract prices. Generally, if the minimum volumes are not purchased and taken during the year, the Company is obligated to pay either: 1) a monthly or annual gas inventory charge calculated as a percentage of the then-current contract commodity price times the minimum quantity not taken; or 2) pay for gas not taken. Alternatively, under some of the contracts, the supplier may exercise a right to reduce its subsequent obligation to provide firm gas to the Company. The Company incurred demand charges in 1998 for firm gas supply, firm transportation service and firm storage and peaking service of $29,571,000, $52,917,000and $8,832,000, respectively.

The following tables summarize the Company's obligations for future demand charges through the primary terms of its existing contracts and the minimum annual take requirements under the gas supply agreements. The quantified obligations are based on current contract prices and FERC authorized rates, which are subject to change.

Demand Charge Obligations

(In Thousands)	1999	2000	2001	2002	2003	2004 & Thereafter	Total
Firm gas supply	$ 29,580	$ 27,271	$27,271	$ 26,941	$ 23,442	$ 17,382	$ 151,887
Firm transportation service	51,331	51,331	51,279	51,227	51,227	136,291	392,686
Firm storage & peaking service	8,885	8,885	8,885	8,885	8,885	87,481	131,906
Total	$ 89,796	$ 87,487	$ 87,435	$ 87,053	$ 83,554	$ 241,154	$676,479

Minimum Annual Take Obligations

(In Thousands of Therms)	1999	2000	2001	2002	2003	2004 & Thereafter	Total
Firm gas supply	472,443	333,957	333,957	329,157	278,132	121,835	1,869,481

The Company believes that all demand charges will be recoverable in rates charged to its customers. Further, pursuant to implementation of FERC Order No. 636, the Company has the right to resell or release to others any of its unutilized gas supply or transportation and storage capacity.

The Company does not anticipate any difficulty in achieving the minimum annual take obligations shown, as such volumes represent less than 57% of expected annual sales for 1999 and less than 39% of expected sales in subsequent years.

The Company's current firm gas supply contracts obligate the suppliers to provide, in the aggregate, annual volumes up to those shown below:

Maximum Supply Available Under Current Firm Supply Contracts

(In Thousands of Therms)	1999	2000	2001	2002	2003	2004 & Thereafter	Total
Firm gas supply	663,402	511,489	511,489	505,489	444,739	289,209	2,925,817

Washington Energy Gas Marketing Company ("WEGM"), a wholly-owned subsidiary, holds firm rights to transport natural gas on the Nova Corporation of Alberta ("Nova"), Alberta Natural Gas Company ("ANG") and PG&E Gas Transmission – Northwest pipelines from Alberta, Canada, to the northern border of California, as well as certain gas storage rights at the Alberta Energy Company ("AECO") field in Alberta and the Jackson Prairie field in western Washington. These rights were formerly held by a wholly-owned subsidiary of Resources but were excluded from the merger of Resources and Cabot completed in May 1994. Following the merger, WEGM entered into a five-year contract with IGI Resources ("IGI"), Boise, Idaho, to manage these rights.

The transportation rights on the PGT pipeline initially consisted of approximately 25,000 MMBtu per day of annual capacity and 20,000 MMBtu per day of winter-only capacity to Stanfield, Oregon, and approximately 20,000 MMBtu per day of annual capacity to the California border. WEGM held similar rights on Nova and ANG.

Effective November 1, 1995, WEGM permanently assigned to IGI all of its Stanfield capacity and associated rights on Nova and ANG. In addition, WEGM segmented its capacity to California at Stanfield and permanently assigned 10,000 MMBtu per day of the Alberta-to-Stanfield rights to a third party effective November 1, 1995. WEGM's remaining PGT rights expire in October 2023, and the ANG and Nova rights expire in October 2008, with annual renewal options. WEGM, as an expansion capacity holder, has been unable to fully recoup its demand charges, which have been approximately 70% higher than those paid by holders of vintage capacity. On September 11, 1996, the FERC approved a request from PGT for the cost of the expansion capacity to be "rolled in" with the cost of the vintage capacity to establish a uniform rate for holders of both types of capacity. This change will be implemented in two stages over six years with the first stage effective November 1, 1996. WEGM's annual obligations for future demand charges through the primary term of WEGM's gas transportation and storage contracts are as follows: 1999, $2,847,000; 2000, $2,843,000; 2001, $2,829,000; 2002, $2,819,000; 2003, $2,296,000 and thereafter, $33,413,000. The IGI management contract provides for incentive payments to IGI based on actual mitigation of demand charges relative to targets established on an annual basis.

As of December 31, 1998, WEGM has a reserve for future losses associated with these contractual obligations of $4,611,000. WEGM initially established the reserve for estimated future losses associated with the transportation and storage obligations with a $16,000,000 ($10,400,000 after tax) charge to earnings upon completion of the merger of Resources and Cabot in May 1994. In the fourth quarter of 1995, WEGM recorded a $5,000,000 ($3,250,000 after tax) charge to increase the reserve based on an assessment of the likelihood and timing of approval of rolled-in rates and actual mitigation results in 1995. During 1998, 1997 and 1996, pre-tax losses totaling $1,916,000, $2,235,000 and $2,652,000, respectively, were charged against the reserve.

Contingencies The Company is subject to environmental regulation by federal, state and local authorities. The Company has been named a Potentially Responsible Party by the Environmental Protection Agency ("EPA") at several contaminated disposal sites and manufactured gas plant sites. The Company has implemented an ongoing program to test, replace and remediate certain underground storage tanks as required by federal and state laws. Remediation and testing of Company vehicle service facilities and storage yards is also continuing.

During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from either insurance companies, third parties or under the Washington Commission's order.

The information presented here as it relates to estimates of future liability is as of December 31, 1998.

Electric Sites The Company has expended approximately $14.5 million related to the remediation activities covered by the Washington Commission's order, of which approximately $7.5 million has been recovered from insurance carriers. At December 31, 1998, approximately $1.8 million has been accrued as a liability for future remediation costs for these and other remediation activities.

Gas Sites Five former WNG or predecessor companies manufactured gas plant ("MGP") sites are currently undergoing investigation, remedial actions or monitoring actions relating to environmental contamination: 1) Everett, Washington; 2) "Gas Works Park" in Seattle, Washington; 3) "Tacoma 22nd and A St." Site in Tacoma, Washington; 4) Chehalis, Washington; and 5) the "Tideflats" area of Tacoma, Washington. Legal and remedial costs incurred to date total approximately $50.9 million and currently estimated future remediation costs are approximately $7.0 million. Work at both the Chehalis and Tideflats sites is substantially completed. To date, the Company has recovered approximately $59 million from insurance carriers and other third parties.

Based on all known facts and analyses, the Company believes it is not likely that the identified environmental liabilities will result in a material adverse impact on the Company's financial position, operating results or cash flow trends.

Litigation Other contingencies, arising out of the normal course of the Company's business, exist at December 31, 1998. The ultimate resolution of these issues is not expected to have a material adverse impact on the financial condition, results of operations or liquidity of the Company.

NOTE 18.

Discontinued Operations

On March 5, 1997, the Company conveyed its interests in undeveloped coal properties through its wholly-owned subsidiary Thermal Energy, Inc. to Wesco Resources, Inc. effective February 1, 1997. The Company's remaining $4.0 million investment in Thermal Energy, Inc. was written off to expense and appears in the consolidated financial statements as discontinued operations. Prior periods have been restated to include Thermal Energy, Inc. operations as discontinued operations.

NOTE 19.

Supplemental Quarterly Financial Data (Unaudited)

The following unaudited amounts, in the opinion of the Company, include all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results of operations for the interim periods. Quarterly amounts vary during the year due to the seasonal nature of the utility business.

(Unaudited; dollars in thousands except per-share amounts)

1998 Quarter	First	Second	Third	Fourth
Operating revenues	$ 522,069	$ 365,525	$ 427,357	$ 592,389
Operating income	$ 99,257	$ 50,012	$ 53,217[1]	$ 96,494
Other income	$ 1,160	$ 3,512	$ 1,433[1]	$ 3,087
Net income	$ 66,003	$ 19,542	$ 21,091	$ 62,976
Basic and diluted earnings per common share	$ 0.74	$ 0.19	$ 0.21	$ 0.71

(Unaudited; dollars in thousands except per-share amounts)

1997 Quarter	First	Second	Third	Fourth
Operating revenues	$ 463,319	$ 352,618	$ 341,021	$ 519,944
Operating income	$ 56,828	$ 45,233	$ 35,421	$ 78,384
Other income	$ 4,884	$ 17,804	$ 6,029	$ (651)
Income from continuing operations	$ 32,608	$ 33,440	$ 11,998	$ 47,652
Net income	$ 29,986	$ 33,440	$ 11,998	$ 47,652
Basic and diluted earnings per common share from continuing operations	$ 0.32	$ 0.33	$ 0.11	$ 0.52

1 Operating income and Other income in the amount of $3.4 million and $4.3 million, respectively, were reclassed to conform the third quarter Form 10-Q with year-end presentation.

NOTE 20.

Consolidated Statement of Cash Flows

For purposes of the Statement of Cash Flows, the Company considers all temporary investments to be cash equivalents. These temporary cash investments are securities held for cash management purposes, having maturities of three months or less. The net change in current assets and current liabilities for purposes of the Statement of Cash Flows excludes short-term debt, current maturities of long-term debt and the current portion of PRAM accrued revenues. At December 31, 1998, $15,710,000 related to a book overdraft was included in accounts payable.

The following provides additional information concerning cash flow activities:

(Year Ended December 31; dollars in thousands)	1998	1997	1996
Changes in certain current assets and current liabilities:			
Accounts receivable	$ (43,003)	$ (4,164)	$ (22,242)
Unbilled revenue	(3,909)	4,591	(11,104)
Materials and supplies	(4,111)	3,316	16,737
Prepayments and other	(1,876)	5,339	1,491
Purchased gas liability	(6,368)	(34,966)	25,814
Accounts payable	27,082	7,132	15,997
Accrued expenses and other	9,493	(39,642)	1,116
Net change in certain current assets and current liabilities	$ (22,692)	$ (58,394)	$ 27,809
Cash payments:			
Interest (net of capitalized interest)	$ 131,567	$ 119,810	$ 113,634
Income taxes	$ 119,664	$ 104,161	$ 98,609

NOTE 21.

Merger of Puget Power and WECo

Included in consolidated results of operations for the month of January 1997 and for the year ended December 31, 1996, are the following results of the previously separate companies for those periods:

	Month Ended January 31, 1997		Year Ended December 31, 1996	
(Dollars in Thousands):	Puget	WECO	Puget	WECO
Revenues	$ 123,051	$ 60,486	$1,223,568	$ 425,711
Net Income	$ 19,671	$ 9,378	$ 135,371	$ 30,148
Common Dividends Declared	$ 29,244	—	$ 117,099	$ 24,149

WECo's operations for the three months ended December 31, 1996, have been reported as an adjustment of $10.8 million to consolidated retained earnings in the first quarter of 1997. WECo's revenues for the three months ended December 31, 1996, were $148.6 million, net income was $16.9 million, common stock issued was $1.0 million and common stock dividends declared were $6.1 million for the same period.

In connection with the merger, the Company recognized direct and indirect merger-related expenses of $55.8 million during the first quarter of 1997. The charge consisted primarily of severance costs of $15.5 million, benefit-related curtailment costs of $9.1 million, transaction costs of $13.7 million and systems and facilities integration costs of $7.2 million. The nonrecurring charge reduced net income by approximately $36.3 million or $0.43 per share. In addition, merger-related costs of $4.8 million were recognized in the fourth quarter of 1996 by Puget Power.

NOTE 22.
Segment Information

The Company primarily operates in one business segment, Regulated Utility Operations. The Company's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The Company's service territory covers approximately 6,000 square miles in the state of Washington.

Principal non-utility lines of business include real estate investment and development, home security services and energy-related services. Reconciling items between segments are not material.

Financial data for business segments are as follows:

(DOLLARS IN THOUSANDS)

1998	REGULATED UTILITY	OTHER	TOTAL
Revenues	$ 1,891,759	$ 15,581	$ 1,907,340
Depreciation & Amortization	165,491	96	165,587
Federal Income Tax	106,967	937	107,904
Operating Income	292,337	6,643	298,980
Interest Charges, net of AFUDC	138,560	—	138,560
Net Income	170,435	(823)	169,612
Total Assets	$ 4,630,501	$ 90,188	$ 4,720,689

1997	REGULATED UTILITY	OTHER	TOTAL
Revenues	$ 1,640,871	$ 36,031	$ 1,676,902
Depreciation & Amortization	161,402	463	161,865
Federal Income Tax	34,230	13,495	47,725
Operating Income	215,126	740	215,866
Interest Charges, net of AFUDC	117,258	976	118,234
Net Income	123,872	(796)	123,076
Total Assets	$ 4,414,396	$ 78,974	$ 4,493,370

1996	REGULATED UTILITY	OTHER	TOTAL
Revenues	$ 1,598,877	$ 50,402	$ 1,649,279
Depreciation & Amortization	143,613	593	144,206
Federal Income Tax	105,236	2,511	107,747
Operating Income	269,652	14,822	284,474
Interest Charges, net of AFUDC	108,688	10,028	118,716
Net Income	171,144	(5,625)	165,519
Total Assets	$ 4,049,113	$ 178,357	$ 4,227,470

SCHEDULE II.

Valuation and Qualifying Accounts and Reserves

(DOLLARS IN THOUSANDS)

	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Deductions	Balance at End of Period
Year Ended December 31, 1998				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 971	$ 5,905	$ 5,855	$ 1,021
Year Ended December 31, 1997				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable[1]	$ 1,700	$ 5,080	$ 5,809	$ 971
Year Ended December 31, 1996				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 1,865	$ 5,920	$ 6,085	$ 1,700

1 Includes additions of $369 and deductions of $384 related to October through December 1996 for WECo.

EXHIBIT INDEX

Certain of the following exhibits are filed herewith. Certain other of the following exhibits have heretofore been filed with the Commission and are incorporated herein by reference.

2.1 Agreement and Plan of Merger dated as of October 18, 1995, among the Registrant, Washington Energy Company and Washington Natural Gas Company. (Exhibit 2.1 to Registration No. 333-617)

3-a Restated Articles of Incorporation of the Company. (Included as Annex F to the Joint Proxy Statement/Prospectus filed February 1, 1996, Registration No. 333-617)

3-b Restated Bylaws of the Company. (Exhibit 3 to Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393)

4.1 Fortieth through Seventy-seventh Supplemental Indentures defining the rights of the holders of the Company's First Mortgage Bonds. (Exhibit 2-d to Registration No. 2-60200; Exhibit 4-c to Registration No. 2-13347; Exhibits 2-e through and including 2-k to Registration No. 2-60200; Exhibit 4-h to Registration No. 2-17465; Exhibits 2-l, 2-m and 2-n to Registration No. 2-60200; Exhibits 2-m to Registration No. 2-37645; Exhibit 2-o through and including 2-s to Registration No. 2-60200; Exhibit 5-b to Registration No. 2-62883; Exhibit 2-h to Registration No. 2-65831; Exhibit (4)-j-1 to Registration No. 2-72061; Exhibit (4)-a to Registration No. 2-91516; Exhibit (4)-b to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393; Exhibits (4)(a) and (4)(b) to Company's Current Report on Form 8-K, dated April 22, 1986; Exhibit (4)a to Company's Current Report on Form 8-K, dated September 5, 1986; Exhibit (4)-b to Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1986, Commission File No. 1-4393; Exhibit (4)-c to Registration No. 33-18506; Exhibit (4)-b to Annual Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393; Exhibit (4)-b to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393; Exhibits (4)-b and (4)-c to Registration No. 33-45916; Exhibit (4)-c to Registration No. 33-50788; Exhibit (4)-a to Registration No. 33-53056; Exhibit 4.3 to Registration No. 33-63278; Exhibit 4.25 to Registration No. 333-41181; and Exhibit 4.27 to Current Report on Form 8-K dated March 5, 1999.)

4.2 Rights Agreement, dated as of January 15, 1991, between the Company and The Chase Manhattan Bank, N.A., as Rights Agent. (Exhibit 2.1 to Registration Statement on Form 8-A filed on January 17, 1991, Commission File No. 1-4393)

4.3 Amendment No. 1 dated as of August 30, 1991, to the Rights Agreement dated as of January 15, 1991, between the Registrant and the Bank of New York (as successor to The Chase Manhattan Bank, N.A.), as Rights Agent. (Exhibit 2.1 to Registration Statement on Form 8 filed on August 30, 1991)

4.4 Amendment No. 2 dated as of October 18, 1995, to the Rights Agreement dated as of January 15, 1991, between the Registrant and The Bank of New York (as successor to The Chase Manhattan Bank, N.A.), as Rights Agent. (Exhibit 1 to Registration Statement on Form 8-A/A filed on October 27, 1995)

4.5 Pledge Agreement dated August 1, 1991, between the Company and The First National Bank of Chicago, as Trustee. (Exhibit (4)-j to Registration No. 33-45916)

4.6 Loan Agreement dated August 1, 1991, between the City of Forsyth, Rosebud County, Montana and the Company. (Exhibit (4)-k to Registration No. 33-45916)

4.7 Statement of Relative Rights and Preferences for the Adjustable Rate Cumulative Preferred Stock, Series B ($25 Par Value). (Exhibit 1.1 to Registration Statement on Form 8-A filed February 14, 1994, Commission File No. 1-4393)

4.8 Statement of Relative Rights and Preferences for the Preference Stock, Series R, $50 Par Value. (Exhibit 1.5 to Registration Statement on Form 8-A filed February 14, 1994, Commission File No. 1-4393)

4.9 Statement of Relative Rights and Preferences for the 7 3/4% Series Preferred Stock Cumulative, $100 Par Value. (Exhibit 1.6 to Registration Statement on Form 8-A filed February 14, 1994, Commission File No. 1-4393)

4.10 Pledge Agreement, dated as of March 1, 1992, by and between the Company and Chemical Bank relating to a series of first mortgage bonds. (Exhibit 4.15 to Annual Report on Form 10-K for the fiscal year ended December 31, 1993, Commission File No. 1-4393)

4.11 Pledge Agreement, dated as of April 1, 1993, by and between the Company and The First National Bank of Chicago, relating to a series of first mortgage bonds. (Exhibit 4.16 to Annual Report on Form 10-K for the fiscal year ended December 31, 1993, Commission File No. 1-4393)

4.12 Form of Statement of Relative Rights and Preferences for the Series II Cumulative Preferred Stock, $25 Par Value (included as Annex F to the Joint Proxy Statement/Prospectus filed February 1, 1996).

4.13 Form of Statement of Relative Rights and Preferences for the Series III Cumulative Preferred Stock, $25 Par Value (included as Annex F to the Joint Proxy Statement/Prospectus filed February 1, 1996).

4.14 Indenture of First Mortgage dated as of April 1, 1957 (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-B, Registration No. 2-14307).

4.15 Sixth Supplemental Indenture dated as of August 1, 1966 (incorporated herein by reference to Washington Natural Gas Company Exhibit to Form 8-K for month of August 1966, File No. 0-951).

4.16 Twelfth Supplemental Indenture dated as of November 1, 1972 (incorporated herein by reference to Washington Natural Gas Company Exhibit to Form 8-K for November 1972, File No. 0-951).

4.17 Seventeenth Supplemental Indenture dated as of August 9, 1978 (incorporated herein by reference to Washington Energy Company Exhibit 5-K.18, Registration No. 2-64428).

4.18 Twenty-sixth Supplemental Indenture dated as of September 1, 1990 (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-B.19, Form 10-K for the year ended September 30, 1990, File No. 0-951).

4.19 Twenty-seventh Supplemental Indenture dated as of September 1, 1990 (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-B.20, Form 10-K for the year ended September 30, 1988, File No. 0-951).

4.20 Twenty-eighth Supplemental Indenture dated as of July 31, 1991 (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-A, Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).

4.21 Twenty-ninth Supplemental Indenture dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4-A of Washington Natural Gas Company's S-3 Registration Statement, Registration No. 33-49599).

4.22 Thirtieth Supplemental Indenture dated as of August 15, 1995 (incorporated herein by reference to Exhibit 4-A of Washington Natural Gas Company's S-3 Registration Statement, Registration No. 33-61859).

10.1 Assignment and Agreement, dated as of August 13, 1964, between Public Utility District No. 1 of Chelan County, Washington and the Company, relating to the Rock Island Project. (Exhibit 13-b to Registration No. 2-24262)

10.2 First Amendment, dated as of October 4, 1961, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and the Company, relating to the Rocky Reach Project. (Exhibit 13-d to Registration No. 2-24252)

10.3 Assignment and Agreement, dated as of August 13, 1964, between Public Utility District No. 1 of Chelan County, Washington and the Company, relating to the Rocky Reach Project. (Exhibit 13-e to Registration No. 2-24252)

10.4 Assignment and Agreement, dated as of August 13, 1964, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Priest Rapids Development. (Exhibit 13-j to Registration No. 2-24252)

10.5 Assignment and Agreement, dated as of August 13, 1964, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Wanapum Development. (Exhibit 13-n to Registration No. 2-24252)

10.6 First Amendment, dated February 9, 1965, to Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and the Company, relating to the Wells Development. (Exhibit 13-p to Registration No. 2-24252)

10.7 First Amendment, executed as of February 9, 1965, to Reserved Share Power Sales Contract between Public Utility District No. 1 of Douglas County, Washington and the Company, relating to the Wells Development. (Exhibit 13-r to Registration No. 2-24252)

10.8 Assignment and Agreement, dated as of August 13, 1964, between Public Utility District No. 1 of Douglas County, Washington and the Company, relating to the Wells Development. (Exhibit 13-u to Registration No. 2-24252)

10.9 Pacific Northwest Coordination Agreement, executed as of September 15, 1964, among the United States of America, the Company and most of the other major electrical utilities in the Pacific Northwest. (Exhibit 13-gg to Registration No. 2-24252)

10.10 Contract dated November 14, 1957, between Public Utility District No. 1 of Chelan County, Washington and the Company, relating to the Rocky Reach Project. (Exhibit 4-1-a to Registration No. 2-13979)

10.11 Power Sales Contract, dated as of November 14, 1957, between Public Utility District No. 1 of Chelan County, Washington and the Company, relating to the Rocky Reach Project. (Exhibit 4-c-1 to Registration No. 2-13979)

10.12 Power Sales Contract, dated May 21, 1956, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Priest Rapids Project. (Exhibit 4-d to Registration No. 2-13347)

10.13 First Amendment to Power Sales Contract dated as of August 5, 1958, between the Company and Public Utility District No. 2 of Grant County, Washington, relating to the Priest Rapids Development. (Exhibit 13-h to Registration No. 2-15618)

10.14 Power Sales Contract dated June 22, 1959, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Wanapum Development. (Exhibit 13-j to Registration No. 2-15618)

10.15 Reserve Share Power Sales Contract dated June 22, 1959, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Priest Rapids Project. (Exhibit 13-k to Registration No. 2-15618)

10.16 Agreement to Amend Power Sales Contracts dated July 30, 1963, between Public Utility District No. 2 of Grant County, Washington and the Company, relating to the Wanapum Development. (Exhibit 13-1 to Registration No. 2-21824)

10.17 Power Sales Contract executed as of September 18, 1963, between Public Utility District No. 1 of Douglas County, Washington and the Company, relating to the Wells Development (Exhibit 13-r to Registration No. 2-21824)

10.18 Reserved Share Power Sales Contract executed as of September 18, 1963, between Public Utility District No. 1 of Douglas County, Washington and the Company, relating to the Wells Development. (Exhibit 13-s to Registration No. 2-21824)

10.19 Exchange Agreement dated April 12, 1963, between the United States of America, Department of the Interior, acting through the Bonneville Power Administration and Washington Public Power Supply System and the Company, relating to the Hanford Project. (Exhibit 13-u to Registration 2-21824)

10.20 Replacement Power Sales Contract dated April 12, 1963, between the United States of America, Department of the Interior, acting through the Bonneville Power Administrator and the Company, relating to the Hanford Project. (Exhibit 13-v to Registration No. 2-21824)

10.21 Contract covering undivided interest in ownership and operation of Centralia Thermal Plant, dated May 15, 1969. (Exhibit 5-b to Registration No. 2-3765)

10.22 Construction and Ownership Agreement dated as of July 30, 1971, between The Montana Power Company and the Company.

(Exhibit 5-b to Registration No. 2-45702)

10.23 Operation and Maintenance Agreement dated as of July 30, 1971, between The Montana Power Company and the Company. (Exhibit 5-c to Registration No. 2-45702)

10.24 Coal Supply Agreement, dated as of July 30, 1971, among The Montana Power Company, the Company and Western Energy Company. (Exhibit 5-d to Registration No. 2-45702)

10.25 Power Purchase Agreement with Washington Public Power Supply System and the Bonneville Power Administration dated February 6, 1973. (Exhibit 5-e to Registration No. 2-49029)

10.26 Ownership Agreement among the Company, Washington Public Power Supply System and others dated September 17, 1973. (Exhibit 5-a-29 to Registration No. 2-60200)

10.27 Contract dated June 19, 1974, between the Company and P.U.D No. 1 of Chelan County. (Exhibit D to Form 8-K dated July 5, 1974)

10.28 Restated Financing Agreement among the Company, lessee, Chrysler Financial Corporation, owner, Nevada National Bank and Bank of Montreal (California), trustee, dated December 12, 1974 pertaining to a combustion turbine generating unit trust. (Exhibit 5-a-35 to Registration No. 2-60200)

10.29 Restated Lease Agreement between the Company, lessee, and the Bank of California, and National Association, lessor, dated December 12, 1974 for one combustion generating unit. (Exhibit 5-a-36 to Registration No. 2-60200)

10.30 Financing Agreement Supplement and Amendment among the Company, lessee, Chrysler Financial Corporation, owner, The Bank of California, National Association, trustee, Pacific Mutual Life Insurance Company, Bankers Life Company, and The Franklin Life Insurance Company, lenders, dated as of March 26, 1975, pertaining to a combustion turbine generating unit trust. (Exhibit 5-a-37 to Registration No. 2-60200)

10.31 Lease Agreement Supplement and Amendment between the Company, lessee, and The Bank of California, National Association, lessor, dated as of March 26, 1975 for one combustion turbine generating unit. (Exhibit 5-a-38 to Registration No. 2-60200)

10.32 Exchange Agreement executed August 13, 1964, between the United States of America, Columbia Storage Power Exchange and the Company, relating to Canadian Entitlement. (Exhibit 13-ff to Registration No. 2-24252)

10.33 Loan Agreement dated as of December 1, 1980 and related documents pertaining to Whitehorn turbine construction trust financing. (Exhibit 10.52 to Annual Report on Form 10-K for the fiscal year ended December 31, 1980, Commission File No. 1-4393)

10.34 Letter Agreement dated March 31, 1980, between the Company and Manufacturers Hanover Leasing Corporation. (Exhibit b-8 to Registration No. 2-68498)

10.35 Coal Supply Agreement for Colstrip 3 and 4, dated as of July 2, 1980; Amendment No. 1 to Coal Supply Agreement, dated as of July 10, 1981, and Coal Transportation Agreement dated as of July 10, 1981. (Exhibit 20-a to Quarterly Report on Form 10-Q for the quarter ended September 30, 1981, Commission File No. 1-4393)

10.36 Residential Purchase and Sale Agreement between the Company and the Bonneville Power Administration, effective as of October 1, 1981. (Exhibit 20-b to Quarterly Report on Form 10-Q for the quarter ended September 30, 1981, Commission File No. 1-4393)

10.37 Letter of Agreement to Participate in Licensing of Creston Generating Station, dated September 30, 1981. (Exhibit 20-c to Quarterly Report on Form 10-Q for the quarter ended September 30, 1981, Commission File No. 1-4393)

10.38 Power sales contract dated August 27, 1982 between the Company and Bonneville Power Administration. (Exhibit 10-a to Quarterly Report on Form 10-Q for the quarter ended September 30, 1982, Commission File No. 1-4393)

10.39 Agreement executed as of April 17, 1984, between the United States of America, Department of the Interior, acting through the Bonneville Power Administration, and other utilities relating to extension energy from the Hanford Atomic Power Plant No. 1. (Exhibit (10)-47 to Annual Report on Form 10-K for the fiscal year ended December 31, 1984, Commission File No. 1-4393)

10.40 Agreement for the Assignment of Output from the Centralia Thermal Project, dated as of April 14, 1983, between the Company and Public Utility District No. 1 of Grays Harbor. (Exhibit (10)-48 to Annual Report on Form 10-K for the fiscal year ended December 31, 1984, Commission File No. 1-4393)

10.41 Settlement Agreement and Covenant Not to Sue executed by the United States Department of Energy acting by and through the Bonneville Power Administration and the Company dated September 17, 1985. (Exhibit (10)-49 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.42 Agreement to Dismiss Claims and Covenant Not to Sue dated September 17, 1985 between Washington Public Power Supply System and the Company. (Exhibit (10)-50 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.43 Irrevocable Offer of Washington Public Power Supply System Nuclear Project No. 3 Capability for Acquisition executed by the Company, dated September 17, 1985. (Exhibit A of Exhibit (10)-50 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.44 Settlement Exchange Agreement ("Bonneville Exchange Power Contract") executed by the United States of America Department of Energy acting by and through the Bonneville Power Administration and the Company, dated September 17, 1985. (Exhibit B of Exhibit (10)-50 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.45 Settlement Agreement and Covenant Not to Sue between the Company and Northern Wasco County People's Utility District, dated October 16, 1985. (Exhibit (10)-53 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.46 Settlement Agreement and Covenant Not to Sue between the Company and Tillamook People's Utility District, dated October 16,

1985. (Exhibit (10)-54 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.47 Settlement Agreement and Covenent Not to Sue between the Company and Clatskanie People's Utility District, dated September 30, 1985. (Exhibit (10)-55 to Annual Report on Form 10-K for the fiscal year ended December 31, 1985, Commission File No. 1-4393)

10.48 Stipulation and Settlement Agreement between the Company and Muckleshoot Tribe of the Muckleshoot Indian Reservation, dated October 31, 1986. (Exhibit (10)-55 to Annual Report on Form 10-K for the fiscal year ended December 31, 1986, Commission File No. 1-4393)

10.49 Transmission Agreement dated April 17, 1981, between the Bonneville Power Administration and the Company (Colstrip Project). (Exhibit (10)-55 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.50 Transmission Agreement dated April 17, 1981, between the Bonneville Power Administration and Montana Intertie Users (Colstrip Project). (Exhibit (10)-56 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.51 Ownership and Operation Agreement dated as of May 6, 1981, between the Company and other Owners of the Colstrip Project (Colstrip 3 and 4). (Exhibit (10)-57 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.52 Colstrip Project Transmission Agreement dated as of May 6, 1981, between the Company and Owners of the Colstrip Project. (Exhibit (10)-58 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.53 Common Facilities Agreement dated as of May 6, 1981, between the Company and Owners of Colstrip 1 and 2, and 3 and 4. (Exhibit (10)-59 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.54 Agreement for the Purchase of Power dated as of October 29, 1984, between South Fork II, Inc. and the Company (Weeks Falls Hydroelectric Project). (Exhibit (10)-60 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.55 Agreement for the Purchase of Power dated as of October 29, 1984, between South Fork Resources, Inc. and the Company (Twin Falls Hydroelectric Project). (Exhibit (10)-61 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.56 Agreement for Firm Purchase Power dated as of January 4, 1988, between the City of Spokane, Washington and the Company (Spokane Waste Combustion Project). (Exhibit (10)-62 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.57 Agreement for Evaluating, Planning and Licensing dated as of February 21, 1985 and Agreement for Purchase of Power dated as of February 21, 1985 between Pacific Hydropower Associates and the Company (Koma Kulshan Hydroelectric Project). (Exhibit (10)-63 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.58 Power Sales Agreement dated as of August 1, 1986, between Pacific Power & Light Company (PacifiCorp) and the Company. (Exhibit (10)-64 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.59 Agreement for Purchase and Sale of Firm Capacity and Energy dated as of August 1, 1986 between The Washington Water Power Company (Avista) and the Company. (Exhibit (10)-65 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.60 Amendment dated as of June 1, 1968, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and the Company (Rocky Reach Project). (Exhibit (10)-66 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.61 Coal Supply Agreement dated as of October 30, 1970, between the Washington Irrigation & Development Company and the Company and other Owners of the Centralia Thermal Project (Centralia Generating Plant). (Exhibit (10)-67 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.62 Interruptible Natural Gas Service Agreement dated as of May 14, 1980, between Cascade Natural Gas Corporation and the Company (Whitehorn Combustion Turbine). (Exhibit (10)-68 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.63 Interruptible Natural Gas Service Agreement dated as of January 31, 1983, between Cascade Natural Gas Corporation and the Company (Fredonia Generating Station). (Exhibit (10)-69 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.64 Interruptible Gas Service Agreement dated May 14, 1981, between Washington Natural Gas Company and the Company (Fredrickson Generating Station). (Exhibit (10)-70 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.65 Settlement Agreement dated April 24, 1987, between Public Utility District No. 1 of Chelan County, the National Marine Fisheries Service, the State of Washington, the State of Oregon, the Confederated Tribes and Bands of the Yakima Indian Nation, Colville Indian Reservation, Umatilla Indian Reservation, the National Wildlife Federation and the Company (Rock Island Project). (Exhibit (10)-71 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.66 Amendment No. 2 dated as of September 1, 1981, and Amendment No. 3 dated September 14, 1987, to Coal Supply Agreement between Western Energy Company and the Company and the other Owners of Colstrip 3 and 4. (Exhibit (10)-72 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.67 Amendatory Agreement No. 1 dated August 27, 1982, and Amendatory Agreement No. 2 dated August 27, 1982, to the Power Sales Contract between the Company and the Bonneville Power

Administration dated August 27, 1982. (Exhibit (10)-73 to Annual Report on Form 10-K for the fiscal year ended December 31, 1987, Commission File No. 1-4393)

10.68 Transmission Agreement dated as of December 30, 1987, between the Bonneville Power Administration and the Company (Rock Island Project). (Exhibit (10)-74 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393)

10.69 Agreement for Purchase and Sale of Firm Capacity and Energy between The Washington Water Power Company and the Company dated as of January 1, 1988. (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1988, Commission File No. 1-4393)

10.70 Amendment dated as of August 10, 1988, to Agreement for Firm Purchase Power dated as of January 4, 1988, between the City of Spokane, Washington and the Company (Spokane Waste Combustion Project).(Exhibit (10)-76 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393)

10.71 Agreement for Firm Power Purchase dated October 24, 1988, between Northern Wasco People's Utility District and the Company (The Dalles Dam North Fishway). (Exhibit (10)-77 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393)

10.72 Agreement for the Purchase of Power dated as of October 27, 1988, between Pacific Power & Light Company (PacifiCorp) and the Company. (Exhibit (10)-78 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393)

10.73 Agreement for Sale and Exchange of Firm Power dated as of November 23, 1988, between the Bonneville Power Administration and the Company. (Exhibit (10)-79 to Annual Report on Form 10-K for the fiscal year ended December 31, 1988, Commission File No. 1-4393)

10.74 Agreement for Firm Power Purchase, dated as of February 24, 1989, between Sumas Energy, Inc. and the Company. (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1989, Commission File No. 1-4393)

10.75 Settlement Agreement, dated as of April 27, 1989, between Public Utility District No. 1 of Douglas County, Washington, Portland General Electric Company (Enron), PacifiCorp, The Washington Water Power Company (Avista) and the Company. (Exhibit (10)-1 to Quarterly Report on Form 10-Q quarter ended September 30, 1989, Commission File No. 1-4393)

10.76 Agreement for Firm Power Purchase (Thermal Project), dated as of June 29, 1989, between San Juan Energy Company and the Company. (Exhibit (10)-2 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1989, Commission File No. 1-4393)

10.77 Agreement for Verification of Transfer, Assignment and Assumption, dated as of September 15, 1989, between San Juan Energy Company, March Point Cogeneration Company and the Company. (Exhibit (10)-3 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1989, Commission File No. 1-4393)

10.78 Power Sales Agreement between The Montana Power Company and the Company, dated as of October 1, 1989. (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1989, Commission File No. 1-4393)

10.79 Conservation Power Sales Agreement dated as of December 11, 1989, between Public Utility District No. 1 of Snohomish County and the Company. (Exhibit (10)-87 to Annual Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393)

10.80 Memorandum of Understanding dated as of January 24, 1990, between the Bonneville Power Administration and The Washington Public Power Supply System, Portland General Electric Company (Enron), Pacific Power & Light Company (PacifiCorp), The Montana Power Company, and the Company. (Exhibit (10)-88 to Annual Report on Form 10-K for the fiscal year ended December 31, 1989, Commission File No. 1-4393)

10.81 Amendment No. 1 to Agreement for the Assignment of Power from the Centralia Thermal Project dated as of January 1, 1990, between Public Utility District No. 1 of Grays Harbor County, Washington and the Company. (Exhibit (10)-89 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.82 Preliminary Materials and Equipment Acquisition Agreement dated as of February 9, 1990, between Northwest Pipeline Corporation and the Company. (Exhibit (10)-90 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.83 Amendment No. 1 to the Colstrip Project Transmission Agreement dated as of February 14, 1990, among the Montana Power Company, The Washington Water Power Company (Avista), Portland General Electric Company (Enron), PacifiCorp and the Company. (Exhibit (10)-91 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.84 Settlement Agreement dated as of February 27, 1990, among United States of America Department of Energy acting by and through the Bonneville Power Administration, the Washington Public Power Supply System, and the Company. (Exhibit (10)-92 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.85 Amendment No. 1 to the Fifteen-Year Power Sales Agreement dated as of April 18, 1990, between Pacificorp and the Company. (Exhibit (10)-93 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.86 Settlement Agreement dated as of October 1, 1990, among Public Utility District No. 1 of Douglas County, Washington, the Company, Pacific Power and Light Company (PacifiCorp), The Washington Water Power Company (Avista), Portland General Electric Company (Enron), the Washington Department of Fisheries, the Washington Department of Wildlife, the Oregon Department of Fish and Wildlife, the National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the Confederated Tribes and Bands of the Yakima Indian Nation, the Confederated Tribes of the Umatilla Reservation, and the Confederated Tribes of the Colville Reservation. (Exhibit (10)-95 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393)

10.87 Agreement for Firm Power Purchase dated July 23, 1990, between Trans-Pacific Geothermal Corporation, a Nevada corporation, and the Company. (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393)

10.88 Agreement for Firm Power Purchase dated July 18, 1990, between Wheelabrator Pierce, Inc., a Delaware corporation, and the Company. (Exhibit (10)-2 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393)

10.89 Agreement for Firm Power Purchase dated September 26, 1990, between Encogen Northwest, L.P., a Delaware corporation, and the Company. (Exhibit (10)-3 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393)

10.90 Agreement for Firm Power Purchase (Thermal Project) dated December 27, 1990, among March Point Cogeneration Company, a California general partnership comprising San Juan Energy Company, a California corporation; Texas-Anacortes Cogeneration Company, a Delaware corporation; and the Company. (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393)

10.91 Agreement for Firm Power Purchase dated March 20, 1991, between Tenaska Washington, Inc., a Delaware corporation, and the Company. (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393)

10.92 Letter Agreement dated April 25, 1991, between Sumas Energy, Inc. and the Company, to amend the Agreement for Firm Power Purchase dated as of February 24, 1989. (Exhibit (10)-2 to Quarterly Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393)

10.93 Amendment dated June 7, 1991, to Letter Agreement dated April 25, 1991, between Sumas Energy, Inc. and the Company. (Exhibit (10)-3 to Quarterly Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393)

10.94 Amendatory Agreement No. 3, dated August 1, 1991, to the Pacific Northwest Coordination Agreement, executed September 15, 1964, among the United States of America, the Company and most of the other major electrical utilities in the Pacific Northwest. (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended June 30, 1991, Commission File No. 1-4393)

10.95 Amendment dated July 11, 1991, to the Agreement for Firm Power Purchase dated September 26, 1990, between Encogen Northwest, L.P., a Delaware limited partnership, and the Company. (Exhibit (10)-1 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1991, Commission File No. 1-4393)

10.96 Agreement between the 40 parties to the Western Systems Power Pool (the Company being one party) dated July 27, 1991. (Exhibit (10)-2 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1991, Commission File No. 1-4393)

10.97 Memorandum of Understanding between the Company and the Bonneville Power Administration dated September 18, 1991. (Exhibit (10)-3 to Quarterly Report on Form 10-Q for the quarter ended September 30, 1991, Commission File No. 1-4393)

10.98 Amendment of Seasonal Exchange Agreement, dated December 4, 1991, between Pacific Gas and Electric Company and the Company. (Exhibit (10)-107 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.99 Capacity and Energy Exchange Agreement, dated as of October 4, 1991, between Pacific Gas and Electric Company and the Company. (Exhibit (10)-108 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.100 Intertie and Network Transmission Agreement, dated as of October 4, 1991, between Bonneville Power Administration and the Company. (Exhibit (10)-109 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.101 Amendatory Agreement No. 4, executed June 17, 1991, to the Power Sales Agreement dated August 27, 1982, between the Bonneville Power Administration and the Company. (Exhibit (10)-110 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.102 Amendment to Agreement for Firm Power Purchase, dated as of September 30, 1991, between Sumas Energy, Inc. and the Company. (Exhibit (10)-112 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.103 Centralia Fuel Supply Agreement, dated as of January 1, 1991, between Pacificorp Electric Operations and the Company and other Owners of the Centralia Steam-Electric Power Plant. (Exhibit (10)-113 to Annual Report on Form 10-K for the fiscal year ended December 31, 1991, Commission File No. 1-4393)

10.104 Agreement for Firm Power Purchase dated August 10, 1992, between Pyrowaste Corporation, Puget Sound Pyroenergy Corporation and the Company. (Exhibit (10)-114 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.105 Memorandum of Termination dated August 31, 1992, between Encogen Northwest, L.P. and the Company. (Exhibit (10)-115 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.106 Agreement Regarding Security dated August 31, 1992, between Encogen Northwest, L.P. and the Company. (Exhibit (10)-116 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.107 Consent and Agreement dated December 15, 1992, between the Company, Encogen Northwest, L.P. and The First National Bank of Chicago, as collateral agent. (Exhibit (10)-117 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.108 Subordination Agreement dated December 17, 1992, between the Company, Encogen Northwest, L.P., Rolls-Royce & Partners Finance Limited and The First National Bank of Chicago. (Exhibit (10)-118 to Annual Report on Form 10-K for the fiscal year ended December

31, 1992, Commission File No. 1-4393)

10.109 Letter Agreement dated December 18, 1992, between Encogen Northwest, L.P. and the Company regarding arrangements for the application of insurance proceeds. (Exhibit (10)-119 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.110 Guaranty of Ensearch Corporation in favor of the Company dated December 15, 1992. (Exhibit (10)-120 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.111 Letter Agreement dated October 12, 1992, between Tenaska Washington Partners, L.P. and the Company regarding clarification of issues under the Agreement for Firm Power Purchase. (Exhibit (10)-121 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.112 Consent and Agreement dated October 12, 1992, between the Company and The Chase Manhattan Bank, N.A., as agent. (Exhibit (10)-122 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.113 Settlement Agreement dated December 29, 1992, between the Company and the Bonneville Power Administration (BPA) providing for power purchase by BPA. (Exhibit (10)-123 to Annual Report on Form 10-K for the fiscal year ended December 31, 1992, Commission File No. 1-4393)

10.114 Contract with W. S. Weaver, Executive Vice President & Chief Financial Officer, dated April 24, 1991. (Exhibit 10.114 to Annual Report on Form 10-K for the fiscal year ended December 31, 1993, Commission File No. 1-4393)

10.115 General Transmission Agreement dated as of December 1, 1994, between the Bonneville Power Administration and the Company (BPA Contract No. DE-MS79-94BP93947) (Exhibit 10.115 to Annual Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393)

10.116 PNW AC Intertie Capacity Ownership Agreement dated as of October 11, 1994 between the Bonneville Power Administration and the Company (BPA Contract No. DE-MS79-94BP94521) (Exhibit 10.116 to Annual Report on Form 10-K for the fiscal year ended December 31, 1994, Commission File No. 1-4393)

10.117 Power Exchange Agreement dated as of September 27, 1995, between British Columbia Power Exchange Corporation and the Company. (Exhibit 10.117 to Annual Report on Form 10-K for the fiscal year ended December 31, 1996, Commission File No. 1-4393)

10.118 Contract with W. S. Weaver, Executive Vice President and Chief Financial Officer, dated October 18, 1996. (Exhibit 10.118 to Annual Report on Form 10-K for the fiscal year ended December 31, 1996, Commission File No. 1-4393)

10.119 Contract with S. M. Vortman, Senior Vice President Corporate and Regulatory Relations, dated October 18, 1996. (Exhibit 10.119 to Annual Report on Form 10-K for the fiscal year ended December 31, 1996, Commission File No. 1-4393)

10.120 Contract with G. B. Swofford, Senior Vice President Customer Operations, dated October 18, 1996. (Exhibit 10.120 to Annual Report on Form 10-K for the fiscal year ended December 31, 1996, Commission File No. 1-4393)

10.121 Service Agreement dated September 1, 1987 between Northwest Pipeline Corporation and Washington Natural Gas Company for SGS-1 firm storage service at Jackson Prairie (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-A Form 10-K for the year ended September 30, 1994, File No. 11271).

10.122 Service Agreement dated April 14, 1993 between Questar Pipeline Corporation and Washington Natural Gas Company for FSS-1 firm storage service at Clay Basin (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-B Form 10-K for the year ended September 30, 1994, File No. 11271).

10.123 Service Agreement dated November 1, 1989, with Northwest Pipeline Corporation covering liquefaction storage gas service filed under cover of Form SE dated December 27, 1989.

10.124 Firm Transportation Service Agreement dated October 1, 1990, between Northwest Pipeline Corporation and Washington Natural Gas Company (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-D Form 10-K for the year ended September 30, 1994, File No. 11271).

10.125 Gas Transportation Service Contract dated June 29, 1990, between Washington Natural Gas Company and Northwest Pipeline Corporation (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-A Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).

10.126 Gas Transportation Service Contract dated July 31, 1991, between Washington Natural Gas Company and Northwest Pipeline Corporation (incorporated herein by reference to Washington Natural Gas Company Exhibit 4-A Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).

10.127 Amendment to Gas Transportation Service Contract dated July 31, 1991, between Washington Natural Gas Company and Northwest Pipeline Corporation.

10.128 Gas Transportation Service Contract dated July 15, 1994, between Washington Natural Gas Company and Northwest Pipeline Corporation

10.129 Amendment to Gas Transportation Service Contract dated August 15, 1994, between Washington Natural Gas Company and Northwest Pipeline Corporation.

10.130 Washington Natural Gas Company Deferred Compensation Plan effective September 1, 1995.

10.131 Form of Washington Natural Gas Company - Executive Retirement Compensation Agreement reflecting all amendments through August 16, 1995.

10.132 Second Washington Energy Company Performance Share Plan (amended and restated effective October 1, 1991) (incorporated herein by reference to Washington Energy Company Exhibit 10-L1, Form 10-K for the year ended September 30, 1991, File No. 0-8745).

10.133 Washington Energy Company Interim Performance Share

Plan effective December 7, 1994.

10.134 Washington Energy Company Stock Option Plan (incorporated herein by reference to Exhibit 10-C Washington Energy Company Form 10-Q for the quarter ended March 31, 1984, File No. 0-8745).

10.135 Amendment to Washington Energy Company Stock Option Plan (incorporated herein by reference to Washington Energy Company Exhibit 10-S, Form 10-K for the year ended September 30, 1986, File No. 0-8745).

10.136 Amendment to Washington Energy Company Stock Option Plan dated as of February 26, 1988 (incorporated herein by reference to Washington Energy Company Form S-8, Registration No. 33-24221).

10.137 Washington Energy Company Stock Option Plan effective December 15, 1993 (incorporated herein by reference to Washington Energy Company Exhibit 99, Registration No. 33-55381).

10.138 Washington Energy Company Directors Stock Bonus Plan (incorporated herein by reference to Washington Energy Company Exhibit 10-O Form 10-K for the year ended September 30, 1990, File No. 0-8745).

10.139 Form of Conditional Executive Employment Contract, filed under cover of Form SE dated December 27, 1988 (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-M.2, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.140 Amended and restated Washington Energy Company and subsidiaries Annual Incentive Plan for Vice Presidents and above, dated October 1994.

10.141 Interest Rate Swap Agreement dated September 27, 1989 between Thermal Resources, Inc. and the First National Bank of Chicago, filed under cover of Form SE dated December 27, 1989, (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-N, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.142 Firm Transportation Service Agreement dated March 1, 1992 between Northwest Pipeline Corporation and Washington Natural Gas Company (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-O, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.143 Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Jackson Prairie (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-P, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.144 Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Jackson Prairie (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-Q, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.145 Firm Transportation Service Agreement dated January 12, 1994 between Northwest Pipeline Corporation and Washington Natural Gas Company for firm transportation service from Plymouth, LNG (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-R, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.146 Service Agreement dated July 9, 1991 with Northwest Pipeline Corporation for SGS-2F Storage Service filed under cover of Form SE dated December 23, 1991 (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-S, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.147 Firm Transportation Agreement dated October 27, 1993 between Pacific Gas Transmission Company and Washington Natural Gas Company for firm transportation service from Kingsgate (incorporated herein by reference to Washington Natural Gas Company Exhibit 10-T, Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.148 Firm Storage Service Agreement and Amendment dated April 30, 1991 between Questar Pipeline Company and Washington Natural Gas Company for firm storage service at Clay Basin filed under cover of Form SE dated December 23, 1991.

10.149 Employment agreement with R. R. Sonstelie, Chairman of the Board, dated January 13, 1998. (Exhibit 10.150 to Annual Report on Form 10-K for the fiscal year ended December 31, 1997, Commission File No. 1-4393)

10-150 Change in control agreement with T. J. Hogan, dated August 17, 1995. (Exhibit 10.152 to Annual Report on Form 10-K for the fiscal year ended December 31, 1997, Commission File No. 1-4393)

10-151 Asset Purchase Agreement between PP&L Global, Inc. and the Company. (Exhibit 2a to current report on form 8-K dated November 13, 1998).

*10-152 Employment agreement with S.A. McKeon, Vice President and General Counsel, dated May 27, 1997.

*10-153 Employment agreement with R.L. Hawley, Vice President and Chief Financial Officer, dated March 16, 1998.

*10-154 Employment agreement with J. Quintana, Vice President External Affairs, dated March 20, 1998.

*12-a Statement setting forth computation of ratios of earnings to fixed charges (1994 through 1998).

*12-b Statement setting forth computation of ratios of earnings to combined fixed charges and preferred stock dividends (1994 through 1998).

*21 Subsidiaries of the Registrant.

*23.1 Consent of independent accountants.

*23.2 Consent of independent accountants.

*27 Financial Data Schedules.

**Filed herewith.*

HISTORICAL FINANCIAL DATA[1]

YEAR ENDED DECEMBER 31;
$ IN THOUSANDS, EXCEPT PER-SHARE AMOUNTS

	1998	1997	1996	1995	1994	% CHANGE '97 TO '98
Operating Revenues						
Electricity sales	$ 1,475,208	$ 1,231,424	$ 1,198,769	$ 1,179,330	$ 1,194,058	19.8
Natural gas sales	416,551	409,447	400,108	420,048	396,407	1.7
Other	15,581	36,031	50,402	31,740	42,020	(56.8)
Total operating revenues	1,907,340	1,676,902	1,649,279	1,631,118	1,632,485	13.7
Operating Expenses						
Purchased electricity	752,147	614,929	562,314	523,514	458,700	22.3
Purchased gas	175,805	179,287	177,719	219,022	223,502	(1.9)
Electric generation fuel	56,557	41,455	40,645	35,658	47,166	36.4
Residential/farm exchange credit	(55,562)	(71,970)	(103,154)	(88,004)	(63,942)	(22.8)
Utility operations and maintenance	237,835	250,565	242,290	258,058	332,574	(5.1)
Other operations and maintenance	7,614	21,256	32,234	29,492	42,019	(64.2)
Depreciation and amortization	165,587	161,865	144,206	141,008	146,971	2.3
Merger costs	—	55,789	4,835	—	—	—
Taxes other than federal income taxes	160,472	160,135	155,969	150,507	145,907	0.2
Federal income taxes	107,905	47,725	107,747	91,519	74,816	126.1
Total operating expenses	1,608,360	1,461,036	1,364,805	1,360,774	1,407,713	10.1
Operating income	298,980	215,866	284,474	270,344	224,772	38.5
Other income (net)	9,192	28,066	1,593	(14,909)	(22,572)	(67.2)
Income before interest charges	308,172	243,932	286,067	255,435	202,200	26.3
Interest charges	138,560	118,234	118,716	127,054	122,888	17.2
Income from continuing operations	169,612	125,698	167,351	128,381	79,312	34.9
Discontinued operations (net of taxes)	—	2,622	1,832	26,597	929	—
Net income	169,612	123,076	165,519	101,784	78,383	37.8
Preferred stock dividend accruals	13,003	17,806	22,181	22,654	20,383	(27.0)
Preferred stock redemptions	—	(471)	—	—	—	—
Income for common stock	$ 156,609	$ 105,741	$ 143,338	$ 79,130	$ 58,000	48.1
Common shares outstanding (average, diluted)	84,768	84,628	84,449	84,193	83,830	(0.1)
Basic and diluted earnings per common share from continuing operations	$ 1.85	$ 1.28	$ 1.72	$ 1.26	$ 0.70	44.5
Basic and diluted earnings per common share from discontinued operations	—	(0.03)	(0.02)	(0.32)	(0.01)	—
Basic and diluted earnings per common share	$ 1.85	$ 1.25	$ 1.70	$ 0.94	$ 0.69	48.0
Dividends per share of common stock	$ 1.84	$ 1.78	$ 1.67	$ 1.67	$ 1.67	—
Total assets (at year-end)	$ 4,720,689	$ 4,493,370	$ 4,227,470	$ 4,244,568	$ 4,496,770	5.1

	1998	1997	1996	1995	1994	% CHANGE '97 TO '98
Indicators and Ratios[1]						
Capitalization (at year-end)						
Debt (including short term maturities)	55.7%	52.9%	65.9%	49.3%	50.7%	5.3
Preferred stock[2]	7.3%	7.9%	6.1%	9.2%	8.7%	(7.6)
Common shareholders' investment	37.0%	39.2%	28.0%	41.5%	40.6%	(5.6)
Average cost of debt	7.2%	7.4%	7.7%	7.7%	7.7%	(2.7)
Times interest earned						
(before federal income taxes)	3.0	2.3	3.1	2.3	2.1	30.4
Dividend yield[3]	6.6%	5.9%	7.0%	7.2%	8.3%	11.9
Dividend payout ratio	99.5%	142.4%	98.2%	177.7%	242.0%	(30.1)
Book value per share	$ 16.00	$ 16.30	$ 16.31	$ 16.27	$ 17.01	(1.8)
Return on average common equity	11.6%	7.7%	10.4%	5.6%	3.9%	50.6
Return on total assets	3.3%	2.4%	3.4%	1.9%	1.3%	37.5
Effective tax rate	40.0%	33.2%	39.0%	39.1%	55.3%	21.6

1 Pro-forma results of Puget Sound Power & Light Company and Washington Energy Company for periods prior to January 1, 1997, except as indicated.
2 Includes $100 million Corporation-obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation.
3 Calculated using Puget Sound Power & Light Company's year-end stock prices for periods prior to January 1, 1997.

HISTORICAL OPERATING DATA[1]

(Year ended December 31)	1998	1997	1996	1995	1994	% change '97 to '98
Energy Sales Revenues						
Electricity[2]						
Residential	$ 540,549	$ 529,990	$ 554,318	$ 524,748	$ 532,124	2.0
Commercial	431,752	414,480	423,139	397,211	375,751	4.2
Industrial	180,959	166,473	170,596	168,501	163,574	8.7
Sales to other utilities	274,972	133,726	67,716	52,567	60,537	105.6
Other[3]	46,976	(13,245)	(17,000)	36,303	62,072	—
Total	1,475,208	1,231,424	1,198,769	1,179,330	1,194,058	19.8
Natural gas						
Residential	253,169	246,747	238,560	231,202	206,602	2.6
Commercial	96,116	97,233	94,251	97,396	91,749	(1.2)
Industrial	40,747	39,356	43,400	70,371	80,252	3.5
Transportation	14,211	14,631	12,812	10,762	8,399	(2.9)
Other[4]	12,308	11,480	11,085	10,317	9,405	7.2
Total	416,551	409,447	400,108	420,048	396,407	1.7
Total energy sales revenues	$ 1,891,759	$1,640,871	$ 1,598,877	$ 1,599,378	$ 1,590,465	15.3
Energy and Transportation Sales Volumes						
Electricity (thousands of MWH)						
Residential	9,314	9,320	9,350	8,972	8,914	(0.1)
Commercial	7,191	7,022	6,807	6,539	6,302	2.4
Industrial	4,073	3,995	3,794	3,721	3,725	2.0
Sales to other utilities	9,940	7,446	4,556	3,804	2,832	33.5
Other[4]	327	160	429	46	128	104.4
Total MWH sales	30,845	27,943	24,936	23,082	21,901	10.4
Natural gas (millions of therms)						
Residential	445	434	422	398	371	2.5
Commercial	194	195	188	180	175	(0.5)
Industrial	115	105	119	188	214	9.5
Transportation	254	277	242	157	120	(8.3)
Total gas volumes	1,008	1,011	971	923	880	(0.3)
Customers Served (annual average)						
Electricity						
Residential	782,095	767,476	754,097	739,173	723,566	1.9
Commercial	94,118	91,517	89,613	87,404	85,203	2.8
Industrial	4,193	4,090	3,993	3,908	3,851	2.5
Other	1,437	1,389	1,371	1,346	1,325	3.5
Total electricity customers[5]	881,843	864,472	849,074	831,831	813,945	2.0

Continued from previous page

(YEAR ENDED DECEMBER 31)		1998		1997		1996		1995		1994	% CHANGE '97 TO '98
Natural gas											
Residential		486,553		465,185		440,586		423,195		403,642	4.6
Commercial		42,273		41,158		39,651		38,378		37,112	2.7
Industrial		3,790		3,801		3,762		3,791		3,833	(0.3)
Transportation		123		128		106		55		36	(3.9)
Total natural gas customers[5]		532,739		510,272		484,105		465,419		444,623	4.4
Heating degree days											
Actual (at Sea-Tac Airport)		4,498		4,599		4,953		3,994		4,341	(2.2)
Normal (30-year average)		4,909		4,908		4,909		4,909		4,911	0.0
% colder (warmer) than average		(8)%		(6)%		1%		(19)%		(12)%	
Average annual residential data											
Electric usage per customer (KWH)		11,909		12,143		12,399		12,139		12,319	(1.9)
Electric revenue per customer	$	721	$	717	$	762	$	727	$	735	0.6
Price per KWH (average)	$	0.061	$	0.059	$	0.062	$	0.060	$	0.060	3.4
Natural gas usage per customer (therms)		914		933		957		941		921	(2.1)
Natural gas revenue per customer	$	520	$	530	$	541	$	546	$	512	(1.9)
Price per therm (average)	$	0.569	$	0.568	$	0.566	$	0.580	$	0.556	0.2
Utility Employees		2,996		2,840		3,068		3,336		3,504	5.5

1 Pro-forma results of Puget Sound Power & Light Company and Washington Energy Company for periods prior to January 1, 1997.
2 Operating Revenues in 1998, 1997, 1996 and 1995 were reduced by $46.7 million, $40.5 million, $41.0 million and $25.1 million respectively, as a result of the Company's sale of $237.7 million of its investment in customer-owned conservation measures.
3 Includes PRAM adjustments and change in unbilled revenue
4 Includes change in unbilled sales.
5 In 1998, approximately 275,000 customers purchased both forms of energy from the company.

COMMON STOCK PRICE

RANGES, VOLUMES AND DIVIDENDS

	1998				1997			
	PRICE RANGE		DIVIDENDS	AVERAGE	PRICE RANGE		DIVIDENDS	AVERAGE
	HIGH	LOW	PER SHARE	DAILY VOLUME	HIGH	LOW	PER SHARE	DAILY VOLUME
First quarter	30 1/4	26 5/8	$0.46	153,420	26	23 1/2	$0.46	181,980
Second quarter	28 5/8	25	$0.46	209,470	26 1/2	23 3/4	$0.46	150,750
Third quarter	28	24 1/16	$0.46	194,440	26 15/16	25 1/8	$0.46	70,980
Fourth quarter	29	25 7/8	$0.46	191,250	30 3/16	25 1/2	$0.46	166,180

Corporate
INFORMATION

CORPORATE HEADQUARTERS
Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
Phone: (425)454-6363

FORM 10-K
A copy of Puget Sound Energy's Annual Report on Form 10-K for the year ending December 31, 1998, as filed with the Securities and Exchange Commission, is available at no charge to shareholders upon request to corporate headquarters. The report also may be obtained through the Securities and Exchange Commission's EDGAR internet site (http://www.sec.com).

TRANSFER AGENT FOR COMMON AND PREFERRED STOCK
ChaseMellon Shareholder Services, L.L.C., maintains the Company's shareholder records, distributes dividend payments and administers the Stock Purchase and Dividend Reinvestment Plan. They may be contacted at the address and phone number provided below (see "Shareholder Records and Services").

DIVIDEND CALENDAR
Quarterly dividends on common stock, as declared by the Board of Directors, normally are paid on the 15th day of February, May, August and November each year.

STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN
Puget Sound Energy's Stock Purchase and Dividend Reinvestment Plan provides a convenient way to reinvest dividends on Puget Sound Energy common stock into additional shares of stock at market price. Shareholders also may make optional cash investments of up to $100,000 per calendar year for the purchase of Puget Sound Energy common stock.

More than 33,000 shareholders, or approximately 58% percent of the Company's 57,000 common shareholders, participated in the plan as of December 31, 1998.

In order to receive a plan prospectus, please contact ChaseMellon Shareholders Services at the address and phone number provided below (see "Shareholder Records and Services").

STOCK EXCHANGE LISTING
Puget Sound Energy common stock is traded under the symbol PSD on the New York Stock Exchange (NYSE). Preferred stock is traded on the NYSE under the symbols PSD-PR, PSD-PRA and PSD-PRC. The stock may be quoted as PugSdEngy or PugetEn in financial publications

AUDITORS
PricewaterhouseCoopers, LLP
Seattle, Washington

GENERAL COUNSEL
Perkins Coie
Seattle and Bellevue, Washington

SHAREHOLDER RECORDS AND SERVICES CONTACTS
ChaseMellon Shareholder Services, L.L.C.
Shareholder Relations Dept.
85 Challenger Road
Ridgefield Park, NJ 07660
(800)997-8438
TDD for hearing impaired:
(800)231-5469
From outside the US: (201)329-8660
Internet address:
www.chasemellon.com

PUGET SOUND ENERGY SHAREHOLDER SERVICES
P.O. Box 97034
Bellevue, WA 98009-9734
(425)462-3898

FINANCIAL ANALYST CONTACT
Robert H. Adams
Director-Investor Relations
(425)462-3808

BANKER CONTACT
Donald E. Gaines
Treasurer
(425)462-3870

NEWS MEDIA CONTACT
Puget Sound Energy 24-hr. Media Line
(888)831-7250

EMPLOYMENT POLICY
Puget Sound Energy is an equal opportunity employer.

Design: Cummings Company, Seattle; Photography: Jeff Corwin, Seattle; Portraits: Kevin Cruff, Seattle

William S. Weaver
President & CEO,
and Member of the
Board of Directors
Puget Sound Energy
Age: 54
Years as Director: 8

Richard R. Sonstelie
Chairman of the
Board
Puget Sound Energy
Age: 53
Years as Director: 12

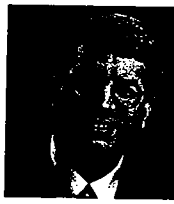
OFFICERS
of Puget Sound Energy

James W. Eldredge
Corporate Secretary,
Controller & Chief
Accounting Officer
Age: 48

Donald E. Gaines
Treasurer
Age: 41

William A. Gaines
Vice President-
Energy Supply
Age: 43

Dorothy A. Graham
Vice President-
Human Resources
Age: 58



Richard L. Hawley
Vice President &
Chief Financial
Officer
Age: 49

Timothy J. Hogan
Vice President-
System Operations
Age: 47

Stephen A. McKeon
Vice President &
General Counsel
Age: 52

Susan McLain
Vice President
Operations-Delivery
Age: 42

Joseph Quintana
Vice President-
External Relations
Age: 50

Gary B. Swofford
Vice President &
Chief Operating
Officer-Delivery
Age: 57

DIRECTORS
of Puget Sound Energy

Douglas P. Beighle
Senior VP (Retired)
The Boeing
Company
Age: 66
Years as Director: 18

Charles W. Bingham
Executive VP
(Retired)
Weyerhaeuser
Company
Age: 65
Years as Director: 21

Phyllis J. Campbell
President
US Bank of
Washington
Age: 47
Years as Director: 6

Donald J. Covey
Chairman of the
Board (Retired)
UNICO Properties
Age: 70
Years as Director: 17*

Robert L. Dryden
Executive VP
(Retired)
Boeing Commercial
Airplane Group
Age: 65
Years as Director: 8*

John D. Durbin
Principal
Olympic Capital
Partners
Age: 63
Years as Director: 15

John W. Ellis
Chairman & CEO
The Baseball Club
of Seattle
Chairman (Retired)
Puget Sound Energy
Age: 70
Years as Director: 30

Daniel J. Evans
Former Governor
& US Senator,
State of Washington
Age: 73
Years as Director: 9

Tomio Moriguchi
Chairman & CEO
Uwajimaya, Inc.
Age: 62
Years as Director: 11*

Sally G. Narodick
CEO & President
Apex Online Learning, Inc.
Age: 53
Years as Director: 10*

**Includes service as a Director of Washington Energy Company*

PUGET SOUND ENERGY, INC.
PO BOX 97034
BELLEVUE, WASHINGTON
98009-9734