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, 2004
OR

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________ to ___________

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-16305	**PUGET ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-1969407
1-4393	**PUGET SOUND ENERGY, INC.** A Washington Corporation 10885 NE 4th Street, Suite 1200 Bellevue, Washington 98004-5591 (425) 454-6363	91-0374630

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

	Title Of Each Class	Name Of Each Exchange On Which Listed
Puget Energy, Inc.	Common Stock, $0.01 par value	NYSE
	Preferred Share Purchase Rights	NYSE
Puget Sound Energy, Inc.	8.4% Capital Securities	NYSE

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

	Title Of Each Class
Puget Sound Energy, Inc.	Preferred Stock (cumulative, $100 par value)
	8.231% Capital Securities

Puget Sound Energy, Inc. meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Indicate by check mark whether the registrants: (1) have 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 registrants were required to file such reports), and (2) have 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. / /

Indicate by check mark whether registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).
Puget Energy, Inc. Yes /X/ No / / Puget Sound Energy, Inc. Yes / / No /X/

The aggregate market value of the voting stock held by non-affiliates of Puget Energy, Inc. as of the last business day of Puget Energy's most recently completed second fiscal quarter was approximately $2,127,279,000. The number of shares of Puget Energy, Inc.'s common stock outstanding at February 23, 2005 was 99,889,474 shares.

All of the outstanding shares of voting stock of Puget Sound Energy, Inc. are held by Puget Energy, Inc.

Documents Incorporated by Reference

Portions of the Puget Energy, Inc. proxy statement for its 2005 Annual Meeting of Shareholders to be filed with the Commission pursuant to Regulation 14A not later than 120 days after December 31, 2004 are incorporated by reference in Part III hereof.

This Annual Report on Form 10-K is a combined report being filed separately by two different registrants: Puget Energy, Inc. and Puget Sound Energy, Inc. Puget Sound Energy, Inc. makes no representation as to the information contained in this report relating to Puget Energy, Inc. and the subsidiaries of Puget Energy, Inc. other than Puget Sound Energy, Inc. and its subsidiaries.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COE	United States Army Corps of Engineers
Dth	Dekatherm (one Dth is equal to one MMBtu)
Ecology	Washington State Department of Ecology
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FPA	Federal Power Act
HCP	Habitat Conservation Plans
InfrastruX	InfrastruX Group, Inc.
kW	Kilowatts (one kilowatt equals one thousand watts)
kWh	Kilowatt Hours (one kWh equals one thousand watt hours)
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
MMBtu	One Million British Thermal Units
MMS	Minerals Management Service
MW	Megawatts (one MW equals one thousand kW)
MWh	Megawatt Hours (one MWh equals one thousand kWh)
NOPR	Notice of Proposed Rulemaking
NYSE	New York Stock Exchange
PCA	Power Cost Adjustment
PGA	Purchased Gas Adjustment
PG&E	Pacific Gas & Electric Company
PSE	Puget Sound Energy, Inc.
PUDs	Washington Public Utility Districts
Puget Energy	Puget Energy, Inc.
PURPA	Public Utility Regulatory Policies Act
RFP	Request for Proposal
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SMD	FERC Standard Market Design
Washington Commission	Washington Utilities and Transportation Commission
WECO	Western Energy Company

FORWARD-LOOKING STATEMENTS

Puget Energy and Puget Sound Energy (PSE) are including the following cautionary statements in this Form 10-K to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of Puget Energy or PSE. This report includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives, assumptions of future events or performance. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue" or similar expressions identify forward-looking statements.

Forward-looking statements involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. Puget Energy's and PSE's expectations, beliefs and projections are expressed in good faith and are believed by Puget Energy and PSE, as applicable, to have a reasonable basis, including without limitation management's examination of historical operating trends, data contained in records and other data available from third parties; but there can be no assurance that Puget Energy's and PSE's expectations, beliefs or projections will be achieved or accomplished.

In addition to other factors and matters discussed elsewhere in this report, some important factors that could cause actual results or outcomes for Puget Energy and PSE to differ materially from those discussed in forward-looking statements include:

Risks relating to the regulated utility business (PSE)

- governmental policies and regulatory actions, including those of the Federal Energy Regulatory Commission (FERC) and the Washington Utilities and Transportation Commission (Washington Commission), with respect to allowed rates of return, financings, industry and rate structures, transmission and generation business structures within PSE, acquisition and disposal of assets and facilities, operation, maintenance and construction of electric generating facilities, operation of distribution and transmission facilities (gas and electric), licensing of hydroelectric operations and gas storage facilities, recovery of other capital investments, recovery of power and gas costs, recovery of regulatory assets, and present or prospective wholesale and retail competition;
- financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways and also adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- wholesale market disruption, which may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices and/or impede PSE's ability to manage its energy portfolio risks;
- the effect of wholesale market structures (including, but not limited to, new market design such as Grid West, a regional transmission organization, and Standard Market Design);
- PSE electric or gas distribution system failure, which may impact PSE's ability to adequately deliver gas supply to its customers;
- weather, which can have a potentially serious impact on PSE's revenues and its ability to procure adequate supplies of gas, fuel or purchased power to serve its customers and on the cost of procuring such supplies;
- variable hydroelectric conditions, which can impact streamflow and PSE's ability to generate electricity from hydroelectric facilities;
- plant outages, which can have an adverse impact on PSE's expenses as it procures adequate supplies to replace the lost energy or dispatches a more expensive resource;
- the ability of gas or electric plant to operate as intended, which if not in proper operating condition or design could limit the capacity of the operating plant;
- the ability to renew contracts for electric and gas supply and the price of renewal;
- blackouts or large curtailments of transmission systems, whether PSE's or others', which can have an impact on PSE's ability to deliver load to its customers;
- the ability to restart generation following a regional transmission disruption;
- failure of the interstate gas pipeline delivering to PSE's system, which may impact PSE's ability to adequately deliver gas supply to its customers;
- the ability to relicense FERC hydroelectric projects at a cost-effective level;
- the amount of collection, if any, of PSE's receivables from the California Independent System Operator (CAISO) and other parties, and the amount of refunds found to be due from PSE to the CAISO or other parties;
- industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- general economic conditions in the Pacific Northwest, which might impact customer consumption or affect PSE's accounts receivable; and

- the loss of significant customers or changes in the business of significant customers, which may result in changes in demand for PSE’s services.

Risks relating to the non-regulated utility service business (InfrastruX Group, Inc.)

- the ability of Puget Energy to complete a sale of its interests in InfrastruX to a third party under reasonable terms;
- the failure of InfrastruX to service its obligations under its credit agreement, in which case Puget Energy, as guarantor, may be required to satisfy these obligations, which could have a negative impact on Puget Energy’s liquidity and access to capital;
- the inability to generate internal growth at InfrastruX, which could be affected by, among other factors, InfrastruX’s ability to expand the range of services offered to customers, attract new customers, increase the number of projects performed for existing customers, hire and retain employees and open additional facilities;
- the effect of competition in the industry in which InfrastruX competes, including from competitors that may have greater resources than InfrastruX, which may enable them to develop expertise, experience and resources to provide services that are superior in quality or lower in price;
- the extent to which existing electric power and gas companies or prospective customers will continue to outsource services in the future, which may be impacted by, among other things, regional and general economic conditions in the markets InfrastruX serves;
- delinquencies, including those associated with the financial conditions of InfrastruX’s customers;
- the impact of any goodwill impairments on the results of operations of InfrastruX arising from its acquisitions, which could have a negative effect on the results of operations of Puget Energy;
- the impact of adverse weather conditions that negatively affect operating conditions and results;
- the ability to obtain adequate bonding coverage and the cost of such bonding; and
- the perception of risk associated with its business due to a challenging business environment.

Risks relating to both the regulated and non-regulated businesses

- the impact of acts of terrorism or similar significant events;
- the ability of Puget Energy, PSE and InfrastruX to access the capital markets to support requirements for working capital, construction costs and the repayment of maturing debt;
- capital market conditions, including changes in the availability of capital or interest rate fluctuations;
- changes in Puget Energy’s or PSE’s credit ratings, which may have an adverse impact on the availability and cost of capital for Puget Energy, PSE and InfrastruX;
- legal and regulatory proceedings;
- the ability to recover changes in enacted federal, state or local tax laws through revenue in a timely manner;
- changes in, adoption of and compliance with laws and regulations including environmental and endangered species laws, regulations, decisions and policies concerning the environment, natural resources, and fish and wildlife (including the Endangered Species Act);
- employee workforce factors, including strikes, work stoppages, availability of qualified employees or the loss of a key executive;
- the ability to obtain and keep patent or other intellectual property rights to generate revenue;
- the ability to obtain adequate insurance coverage and the cost of such insurance;
- the impacts of natural disasters such as earthquakes, hurricanes, floods, fires or landslides;
- the impact of adverse weather conditions that negatively affect operating conditions and results;
- the ability to maintain effective internal controls over financial reporting; and
- the ability to maintain customers and employees.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, Puget Energy and PSE undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

PART I

ITEM 1. BUSINESS

GENERAL

Puget Energy, Inc. (Puget Energy) is an energy services holding company incorporated in the State of Washington in 1999. All of its operations are conducted through its subsidiaries, Puget Sound Energy, Inc. (PSE), a utility company, and InfrastruX Group, Inc. (InfrastruX), a construction services company. Puget Energy has no significant assets other than the stock of its subsidiaries. Subject to limited exceptions, Puget Energy is exempt from regulation as a public utility holding company pursuant to Section 3(a)(1) of the Public Utility Holding Company Act of 1935. Puget Energy and PSE are collectively referred to herein as "the Company." The following table provides the percentages of Puget Energy's consolidated operating revenues and net income generated and assets held by the reportable segments:

Segment	Percent of Revenue			Percent of Net Income			Percent of Assets		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
Puget Sound Energy[1]	85.3%	85.4%	85.8%	224.2%	98.1%	87.4%	94.5%	92.7%	92.2%
InfrastruX	14.4%	14.3%	13.8%	(127.8)%	1.5%	8.6%	4.3%	6.0%	5.5%
Other subsidiaries	0.3%	0.3%	0.4%	3.6%	0.4%	4.0%	1.2%	1.3%	2.3%

[1] *Net income for PSE is presented as net income for common stock due to $5.2 million and $7.8 million of preferred stock dividend being treated as an other deduction at Puget Energy in 2003 and 2002, respectively*

Additional financial data regarding these segments are included in Note 24, to the Consolidated Financial Statements included with this report.

PUGET ENERGY STRATEGY

Puget Energy is the parent company of the largest electric and natural gas utility headquartered in the State of Washington, primarily engaged in the business of electric transmission, distribution and generation and natural gas transmission and distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by focusing primarily on the regulated utility business conducted through PSE. The key elements of this strategy include:

Focus on regulated utility business. PSE intends to continue to focus on its core electric and natural gas transmission and distribution utility business, offering reliable electric and gas service at a fair value to PSE's customers.

Add electric generation and delivery infrastructure to meet customer needs. Ensuring reliable, low-cost energy supply is one of PSE's highest priorities. As regional demand for energy continues to grow, PSE's committed power supply resources will not be adequate to meet anticipated demand, especially as existing long-term power purchase contracts begin to expire. Accordingly, PSE is continually seeking new electric power resource generation and long term purchase power agreements to meet load requirements and ensure stable cost-based energy supply within its service territory. During 2004, PSE made the following strides in this goal:

- Purchased a 49.85% interest in a 250 MW capacity gas-fired generation facility in western Washington, which went into service in April 2004.
- Signed a two-year purchase power agreement in the second quarter 2004 with a utility for 85 MW of energy with delivery beginning January 1, 2005.
- Signed a non-binding letter of intent in September 2004 to purchase a wind generation facility with up to 230 MW of generation to be developed in central Washington State.
- Signed a non-binding letter of intent in October 2004 to purchase a wind generation facility with up to 150 MW of generation to be developed in eastern Washington State.

Rebuild financial strength to fund energy infrastructure and manage energy portfolio. PSE intends to focus on the regulated business to improve its credit quality and liquidity and to provide predictable earnings to attract investors in Puget Energy.

Provide return to Puget Energy shareholders through earnings growth and dividends. Generate return and attract equity capital through growth in PSE earnings and dividends.

Achieve PSE earnings growth. PSE earnings will grow through rebuilding common equity and increasing ratebase by adding generating and delivery resources where needed with timely cost recovery. Puget Energy was able to invest additional capital in PSE through the sale of its common stock.

After completing a strategic review of InfrastruX, Puget Energy has decided to exit the construction services sector. Puget Energy's Board of Directors approved the decision on February 8, 2005. The decision to exit the business is the result of the Company's need to invest in the core utility business to acquire or construct energy generating resources and energy delivery infrastructure. During 2005, Puget Energy intends to monetize its interest in InfrastruX through sale or third party recapitalization and invest the proceeds in PSE.

PUGET SOUND ENERGY, INC.

PSE is a public utility incorporated in the State of Washington. PSE furnishes electric and gas service in a territory covering approximately 6,000 square miles, principally in the Puget Sound region of the State of Washington.

At December 31, 2004, PSE had approximately 1,001,200 electric customers, consisting of 884,500 residential, 110,500 commercial, 3,900 industrial and 2,300 other customers; and approximately 672,000 gas customers, consisting of 619,000 residential, 50,200 commercial, 2,700 industrial and 100 transportation customers. At December 31, 2004, approximately 324,200 customers purchased both electricity and gas from PSE. For the year 2004, PSE added approximately 23,500 electric customers and approximately 27,400 gas customers, representing annualized customer growth rates of 2.4% and 4.2% respectively. During 2004, PSE's billed retail and transportation revenues from electric utility operations were derived 47% from residential customers, 44% from commercial customers, 7% from industrial customers and 2% from transportation and other customers. PSE's retail revenues from gas utility operations were derived 63% from residential customers, 30% from commercial customers, 5% from industrial customers and 2% from transportation customers. During this period the largest customer accounted for approximately 1% of PSE's operating revenues.

PSE is affected by various seasonal weather patterns throughout the year and, therefore, utility 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. PSE normally experiences its highest retail energy sales in the first and fourth quarters of the year. Sales of electricity to wholesale customers also vary by quarter and year depending principally upon fundamental market factors and weather conditions. PSE has a purchased gas adjustment (PGA) mechanism in retail gas rates to recover variations in gas supply and transportation costs. PSE also has a power cost adjustment (PCA) mechanism in electric rates to recover variations in electricity costs on a shared basis between customers and PSE.

In the five-year period ended December 31, 2004, PSE's gross electric utility plant additions were $786 million and retirements were $290 million. In the five-year period ended December 31, 2004, PSE's gross gas utility plant additions were $586 million and retirements were $74 million. In the same five-year period, PSE's gross common utility plant additions were $128 million and retirements were $33 million. Gross electric utility plant at December 31, 2004 was approximately $4.4 billion, which consisted of 60% distribution, 26% generation, 6% transmission and 8% general plant and other. Gross gas utility plant as of December 31, 2004 was approximately $1.9 billion, which consisted of 85% distribution, 7% transmission and 8% general plant and other. Gross common utility general and intangible plant at December 31, 2004 was approximately $410 million.

INFRASTRUX GROUP, INC.

InfrastruX was incorporated in the State of Washington in 2000 to pursue the non-regulated construction services business. InfrastruX provides infrastructure construction services to the electric and gas utility industries. InfrastruX has acquired 12 companies, primarily in the Midwest, Texas, south-central and eastern United States, that are engaged in some or all of the following services and activities in their respective regions or nationally:

- Electric: Overhead and underground power line and cable construction, installation and maintenance, including high-voltage transmission and distribution lines, copper and fiberoptic cables; duct installation; revitalization and damage prevention for underground power lines and cables using the patented Cablecure® treatment; substation construction; and other specialty services for new and existing infrastructures.

- Gas: Large-diameter pipeline installation and maintenance; service lines and meters; conventional river crossings and bridge maintenance; cathodic protection; power station fabrication and installation; vacuum excavation; hydrostatic testing; internal pipeline inspection; product pipelines; and other specialty services for distribution and transmission pipeline services including small, mid-size and large-bore directional drilling for virtually all pipeline diameters and soil conditions.

Following a strategic review of InfrastruX conducted by Puget Energy management, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. During 2005, Puget Energy intends to monetize its interest in InfrastruX through a sale or third party recapitalization and to invest the proceeds in PSE. The costs associated with exiting the InfrastruX business cannot be quantified at this time. However, Puget Energy believes that such costs will not be material given the effects of the impairment charge recorded in the fourth quarter 2004.

InfrastruX is affected by seasonal weather conditions and, therefore, revenues and associated expenses are not generated evenly during the year. InfrastruX will usually experience its highest revenues in the second and third quarter of the year, as spring and summer months are routinely the most productive time of year for the construction industry due to longer daylight hours and generally better weather conditions.

InfrastruX's operating strategy revolves around leveraging the synergies of a core group of outstanding infrastructure construction contractors whose asset base, expertise, local knowledge, relationships and years of successful operations form a strong base for a growing business. The ability to share workforce, production equipment and expertise within and between regional geographies allows InfrastruX to provide local support for its customers and also move quickly to provide additional services as needs arise. The formation of regional service centers in 2003, where appropriate, is providing enhanced oversight and control as well as cost efficiencies surrounding back office operations, equipment control and other operational areas.

The construction services industry is both highly competitive and highly fragmented as a result of low barriers to entry, the historical geographic segmentation of utility customers and the natural limitations of service delivery. Competitors of InfrastruX include large established and emerging national companies and many smaller regional companies.

EMPLOYEES

At February 23, 2005, Puget Energy and its subsidiaries had approximately 4,900 full-time employees:

Puget Sound Energy	2,200
InfrastruX	2,700
Total Puget Energy	4,900

Approximately 1,100 PSE employees are represented by the International Brotherhood of Electrical Workers Union (IBEW) or the United Association of Plumbers and Pipefitters (UA). The labor contracts with the IBEW and UA run through 2007 and 2006, respectively.

Approximately 300 InfrastruX employees are represented by the IBEW, UA, United Steelworkers of America, Laborers International Union of North America or other unions. Some unions have annual contract renewals while others have multiple-year contracts.

CORPORATE LOCATION

Puget Energy's and PSE's principal executive offices are located at 10885 NE 4th Street, Suite 1200, Bellevue, Washington 98004 and the telephone number is (425) 454-6363.

AVAILABLE INFORMATION

The Company's reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available or may be accessed free of charge through the Investors section of the Company's website at www.pse.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the SEC. It is not intended that the

Company's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC Internet website at www.sec.gov.

In addition, the following corporate governance materials of the Company are available in the Investors section of the Company's website, and a copy will be mailed upon request. Requests should be made to Puget Energy, Inc., Investor Services, P.O. Box 97034, PSE-08S, Bellevue, Washington 98009-9734.

- Corporate Governance Guidelines;
- Corporate Ethics and Compliance Code;
- Audit Committee, Governance and Public Affairs Committee and Compensation and Leadership Development Committee charters; and
- Code of Ethics for the Company's Chief Executive Officer and senior financial officers.

If the Company waives any material provision of its Code of Ethics for its Chief Executive Officer and senior financial officers or its Corporate Ethics and Compliance Code, or substantively changes the codes for any specific officer, the Company will disclose that waiver on its website within five business days.

NEW YORK STOCK EXCHANGE CERTIFICATION

On May 6, 2004, the Chief Executive Officer of Puget Energy and PSE filed a Section 303A.12(a) CEO Certification with the New York Stock Exchange. The CEO Certification attests that the Chief Executive Officer is not aware of any violations by the Company of NYSE's Corporate Governance Listing Standards.

REGULATION AND RATES

PSE is subject to the regulatory authority of (1) the Washington Commission as to retail utility rates, accounting, the issuance of securities and certain other matters and (2) FERC with respect to the transmission of electric energy, the resale of electric energy at wholesale, accounting and certain other matters.

ELECTRIC REGULATION AND RATES

WASHINGTON COMMISSION MATTERS

On February 18, 2005, the Washington Commission approved a 4% general tariff electric rate case increase to recover higher costs of providing electric service to customers. The rate increase will increase electric revenues by approximately $56.6 million annually effective March 4, 2005. In the order, the Washington Commission also approved a capital structure containing 43% common equity with a return on common equity of 10.3%. In the proceeding PSE had filed a request for an increase of 7.1% or $99.8 million annually on final rebuttal during the rate case, reflecting updated power costs for increases in natural gas prices for generating plants.

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a disallowance of $25.6 million for the PCA 1 period (July 1, 2002 through June 30, 2003), which was recorded by PSE as a Purchased Electricity expense in the second quarter 2004. The order also established guidelines for future recovery of Tenaska costs. The amounts were determined to be a $25.6 million disallowance for the PCA 1 period and an estimated disallowance of $11.3 million for the PCA 3 period (July 1, 2004 to June 30, 2005), based upon applying the Washington Commission's methodology of 50% disallowance on the return on the Tenaska regulatory asset due to projected costs exceeding the benchmark during the period. For the PCA 3 period, approximately $5.6 million was disallowed in the period July 1, 2004 through December 31, 2004, primarily as a reduction to Electric Operating Revenue. While the Washington Commission did not expressly address the disallowance for the PCA 2 period (July 1, 2003 through June 30, 2004), PSE estimated the disallowance for the PCA 2 period to be approximately $12.2 million if the Washington Commission were to follow the same methodology as they have ordered for the PCA 3 period. Therefore, PSE recorded a $12.2 million disallowance to Purchased Electricity expense in the second quarter 2004 for the 50% disallowance of the return on the Tenaska regulatory asset in accordance with the Washington Commission's methodology discussed in their order of May 13, 2004 for a cumulative impact on earnings of $43.4 million in 2004 for the PCA 1, PCA 2 and PCA 3 periods. PSE has filed the PCA 2 period compliance filing and anticipates it will be concluded no later than the first quarter 2005. As a result of the disallowance recorded, the PCA customer deferral was expensed and a reserve was established for amounts not previously deferred under the PCA mechanism. The reserve balance as of December 31, 2004 was $3.2 million, which is expected to be utilized in 2005 as excess power costs are shared through the PCA mechanism.

PSE filed the PCA 2 period compliance filing in August 2004 and received an order from the Washington Commission on February 23, 2005. In the PCA 2 compliance order, the Washington Commission approved the Washington Commission staff's recommendation for an additional return related to the Tenaska regulatory asset in the amount of $6.1 million related to the period July 1, 2003 through December 31, 2003. Washington Commission staff's recommendation was opposed by certain other parties. This amount alters the PCA deferral and is subject to reconsideration and appeal by other parties. Parties have 10 days from February 23, 2005 to file for reconsideration and 30 days to appeal the order. Once the statutory appeal process has concluded and the Washington Commission issues its final order, PSE will determine if recording a regulatory asset is appropriate.

In the May 13, 2004 order, the Washington Commission established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

The Washington Commission guidelines for determining future recovery of the Tenaska costs (gas costs, recovery of the Tenaska regulatory asset and return on the Tenaska regulatory asset) are as follows:

1. The Washington Commission will determine if PSE's gas purchasing plan and gas purchases for Tenaska are prudent through the PCA compliance filings.
2. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, and if PSE's actual Tenaska costs fall at or below the benchmark, it will recover fully its Tenaska costs.
3. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, but its actual Tenaska costs exceed the benchmark, PSE will only recover 50% of the lesser of:
   a) actual Tenaska costs that exceed the benchmark; or
   b) the return on the Tenaska regulatory asset.
4. If PSE's gas purchasing plan or gas purchases are found to be imprudent in a future proceeding, PSE risks disallowance of any and all Tenaska costs.

The Washington Commission confirmed that if the Tenaska gas costs are deemed prudent, PSE will recover the full amount of actual gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded.

In the first quarter 2004, a counterparty of a physical gas supply contract for one of PSE's electric generating facilities notified PSE that it would be unable to deliver physical gas supply beginning in November 2005 through the end of the contract in June 2008. In October 2004, PSE and the counterparty reached a settlement on the non-deliverable period of November 2005 through June 2008. The agreement allows PSE to recover a portion of the present value of the difference in future market prices of physical gas and the original contract price, for a total recovery of approximately $10.1 million. In October 2004, PSE entered into a new contract with another counterparty for the period November 2005 through June 2008 to replace the physical gas supply from the previously mentioned amended contract. Also, in the fourth quarter 2004, an accounting order was approved by the Washington Commission to defer the counterparty settlement amount as a regulatory liability and amortize the benefit over the period of November 2005 through June 2008 as a reduction in Electric Generation Fuel expense. In its accounting order, the Washington Commission reserved the right to review the prudence of the level of settlement payments agreed to and the cost of the replacement contract during any affected PCA periods going forward.

On June 20, 2002, the Washington Commission issued final regulatory approval of the comprehensive electric rate settlement submitted by PSE, key constituents and customer groups, Washington Commission staff and the Washington State Attorney General's Public Counsel Section. The authorization granted PSE a 4.6% electric general rate increase that began July 1, 2002, which was intended to generate approximately $59 million in additional revenue annually. In addition, the settlement provided for an 8.76% overall return on capital based on a projected capital structure with an equity component of 40% and an authorized 11% return on common equity. The settlement resolved all electric and gas cost allocation issues and established an 8.76% overall return on capital.

The settlement also included a Power Cost Adjustment (PCA) mechanism that triggers if PSE's costs to provide customers' electricity falls outside certain bands from a normalized level of power costs established in the electric general rate case. The cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 is limited to $40 million plus 1% of the excess. Upon expiration of the $40 million cumulative cap, the annual power cost variability is subject to the bands in the table below. All significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability).

Upon expiration of the cumulative cap, the most significant risks are hydroelectric generation variability and wholesale market prices of natural gas and power. On an annual July through June basis, the PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers in the following manner:

Annual Power Cost Variability	Customers' Share	Company's Share [1]
+/- $20 million	0%	100%
+/- $20 - $40 million	50%	50%
+/- $40 - $120 million	90%	10%
+/- $120 million	95%	5%

[1] *Over the four-year period July 1, 2002 through June 30, 2006, the Company's share of pre-tax power cost variations is capped at a cumulative $40 million plus 1% of the excess. Power cost variation after June 30, 2006 will be apportioned on an annual basis, based on the graduated scale.*

Interest will be accrued on any overcollection or undercollection of the customers' share of the excess power cost that is deferred. PSE can request a PCA rate surcharge, if for any 12-month period, the actual or projected deferred power costs exceed $30 million. PSE's cumulative share of the excess power costs through December 31, 2004 was $35.0 million, principally because of adverse hydroelectric conditions, escalating wholesale gas and power costs in 2003 and 2004 and a May 2004 Washington Commission order in the PCA 1 compliance filing which stated PSE was not prudent in managing the Tenaska electric generation facility gas cost and ordered PSE to adjust its PCA deferral account to reflect a disallowance for the PCA 1 period (July 1, 2002 through June 30, 2003). PSE's share of the excess power costs, including the effect of the Tenaska disallowance, was $36.5 million in 2004 compared to $34.8 million in 2003. As a result of the Tenaska disallowance reserve, any further increases in variable power costs in excess of the cap under the PCA mechanism through June 2006 would be apportioned 99% to customers and 1% to PSE. PSE is required to file a compliance filing with the Washington Commission annually by August 31, in relation to the power costs under the PCA mechanism for the relevant 12 month period ending June 30.

The settlement also gave PSE the financial flexibility to rebuild its common equity ratio to at least 39% over a three-and-one-half-year period, with milestones of 34%, 36% and 39% at the end of 2003, 2004 and 2005, respectively. If PSE should fail to meet this schedule, it would be subject to a 2% rate reduction penalty. As of December 31, 2004, PSE has restored its common equity ratio to a 40.1% level, exceeding the required level for 2004 by 4.1%.

In the settlement of the 2001 Electric General Rate Proceeding, the Washington Commission and PSE agreed to create a limited-scope proceeding called a Power Cost Only Rate Case (PCORC) that would periodically reset power cost rates. The main objective of the PCORC proceeding is to provide for timely review of new resource acquisitions and inclusion of those costs into rates by the time the new resource goes into service. To achieve this objective, the Washington Commission and PSE have agreed to a non-binding, expedited five-month timeline rather than the statutory 11-month timeline that is allowed in a general rate case.

On October 24, 2003, PSE filed a PCORC proceeding under this 2001 rate case provision for the acquisition and recovery in rates of a 49.85% interest in the Frederickson 1 generating facility, located in Washington State. On April 23, 2004, the acquisition of the Frederickson 1 generating facility was approved by FERC. Prior to that approval, on April 7, 2004, the Washington Commission issued an order in PSE's PCORC granting approval for the acquisition of the Frederickson 1 generating facility as well. As a result of these approvals, PSE completed the acquisition in the second quarter 2004. In its order, the Washington Commission found the acquisition to be prudent and the costs associated with the generating facility reasonable. The costs associated with the generating facility, including projected baseline gas costs, are approved for recovery in rates. The Washington Commission subsequently ordered on May 13, 2004, an increase of cost recovery in rates of $44.1 million annually, beginning May 24, 2004, which includes the ownership, operation and fuel costs of the Frederickson 1 generating facility.

RESIDENTIAL AND SMALL FARM EXCHANGE BENEFIT CREDIT

In June 2001, PSE and Bonneville Power Administration (BPA) entered into an amended settlement agreement regarding the Residential Purchase and Sale Program, under which PSE's residential and small farm customers receive the benefits of federal power. Completion of this agreement enabled PSE to continue to provide a Residential and Farm Energy Exchange Benefit Credit to residential and small farm customers. The amended settlement agreement provides that, for its residential and small farm customers, PSE will receive; (a) cash payment benefits during the period July 1, 2001 through September 30, 2006, and (b) benefits in the form of power or cash payments during the period October 1, 2006 through September 30, 2011. Under the amended settlement agreement regarding the Residential Purchase and Sale Program, PSE reduces residential and small farm customers' revenue on a per kWh basis through the Residential and Farm Energy Exchange Benefit Credit. The credit has no impact on PSE's electric margin or net income, as a corresponding reduction is included in purchased electricity expenses.

In June 2002, PSE entered into an agreement with BPA, which modified the payment provisions of the June 2001 amended settlement agreement to provide for conditional deferral of payment by BPA of certain amounts to be paid under the original agreement for an eight month period beginning February 2003, for a total deferral of $27.7 million. Except for certain adjustments tied to a BPA rate adjustment clause, BPA is to begin paying back the amount deferred with interest over a 60-month period beginning October 1, 2006.

In January 2003, PSE filed revised tariff sheets with the Washington Commission to reflect this modification to the agreement between PSE and BPA. The Washington Commission accepted the tariff changes and the Residential and Farm Energy Exchange Benefit Credit was changed to $0.01740 per kWh from $0.01817 per kWh for the period February 15, 2003 through September 30, 2006.

On June 30, 2003, BPA adopted its final Record of Decision in the February 2003 rate case, which established a formula under the BPA rate adjustment clause to be used in adjusting the rate that will affect the level of residential exchange benefits for PSE's customers. The adjustment under the formula went into effect on October 1, 2003, resulting in both a reduction of benefits of $1.0 million a month for a 12-month period and, under the modified amended settlement agreement mentioned above, an offsetting acceleration of the payment of the above-described $27.7 million deferral. The net result is no change in the cash being received from BPA for the 12-month period, but a reduction in the total benefits to be received in the October 1, 2003 through September 30, 2011 period.

In May 2004, PSE and BPA entered into an agreement that modified the payment of benefits under the amended settlement agreement for the period October 1, 2006 through September 30, 2011. The agreement provides that all benefits in this period will be in the form of cash payments only and defined a new methodology to be used to calculate the residential benefits. In addition, PSE agreed to waive payment of approximately one-half of an available reduction-in-risk discount and deferred payment of the other half of the discount, plus interest, until October 2007.

For 2004 and 2003, the Residential and Farm Energy Exchange Benefit credited to customers was $182.6 million and $181.9 million, respectively, with a related offset to power costs. PSE received payments from BPA in the amount of $175.9 million and $147.9 million during 2004 and 2003, respectively. The difference between the customers' credit and the amount received from BPA either increases or decreases the previously deferred amount owed to customers. The aggregated deferred amount is recorded on PSE's balance sheet as restricted cash. Absent certain adjustments tied to the BPA rate adjustment clause described above, the modified amended settlement agreement will provide for payments from BPA in the amount of $630.6 million for the period January 2003 through September 2006 and for a pass-through of the same amount to eligible residential and small farm customers.

There are several actions in the U.S. Ninth Circuit Court of Appeals against BPA, in which the petitioners assert or may assert that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing, a number of contracts, including the amended settlement agreement and the May 2004 agreement between BPA and PSE described above. BPA rates used in such amended settlement agreement between BPA and PSE for determining the amounts of money to be paid to PSE by BPA under the amended settlement agreement and other agreements described above during the period October 1, 2001 through September 30, 2006 have been confirmed, approved and allowed to go into effect by FERC. There are also several actions in the U.S. Ninth Circuit Court of Appeals against BPA, in which petitioners assert that BPA acted contrary to law in adopting or implementing the rates or rate adjustment clause upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period are based. It is not clear what impact, if any, review of such rates and the above described U.S. Ninth Circuit Court of Appeals actions may have on PSE.

FERC Matters

PSE's market-based rate tariff was accepted by FERC in an order dated January 29, 1999. Pursuant to this order, PSE is required to file an updated market power analysis every three years. On August 11, 2004, PSE filed an updated market power analysis with FERC as required by a FERC order dated May 13, 2004. The August 11, 2004 filing was supplemented by additional filings on September 24, 2004 and November 19, 2004. On December 20, 2004, FERC issued an order (December 20 order) finding that PSE had not provided sufficient information for FERC to determine if PSE had passed the generation market power screens with respect to wholesale sales within PSE's control area. The order instituted an investigation under Section 206 of the Federal Power Act (FPA) and established a prospective refund date of February 27, 2005. Both the proceeding and the refund effective date affect only wholesale sales at market-based rates by PSE inside its own control area. On February 1, 2005, PSE submitted to FERC additional information in accordance with the December 20 order. PSE has been in discussions with FERC staff to ensure that this supplemental filing addresses the staff's issues. Although PSE anticipates a favorable outcome to this matter, there can be no assurance that the outcome will not materially impact PSE.

On November 1, 1999, PSE acquired Encogen Northwest, LP (Encogen) whose sole asset is a natural gas-fired cogeneration facility located in Washington State. With the approval of the Washington Commission, the Encogen facility has been operated as part of PSE's least cost generation dispatch portfolio to serve its native load obligations since it was acquired in 1999. Two wholly-owned subsidiaries of PSE, GP Acquisition Corporation and LP Acquisition Corporation, are the general and limited partners of Encogen, respectively. On December 29, 2004, PSE filed an application with FERC pursuant to Section 203 of the FPA to transfer the Encogen facility to PSE and eliminate the various subsidiaries via an Agreement and Plan of Merger (Merger). On February 15, 2005, FERC issued an order authorizing the Encogen plant to be transferred to PSE. PSE anticipates completing the Merger in 2005.

Gas Regulation and Rates

In 2003, the Washington Commission's Pipeline Safety staff conducted a natural gas standard inspection for three counties within Washington State in which PSE operates gas pipelines. The inspection included a review of procedures, records and operations and maintenance activities. On June 29, 2004, the Washington Commission issued a complaint to PSE related to that inspection, alleging certain violations of Washington Commission regulations. In December 2004, PSE and the Washington Commission resolved the issues. PSE agreed to a penalty of $0.5 million, and also agreed to update certain natural gas operating practices. PSE's financial results in 2004 reflect the impact of this penalty. In addition, the resolution included the potential for future penalties of up to $0.2 million in the next ten years if certain operational goals are not met. The Washington Commission approved the settlement on January 31, 2005.

PSE has a PGA mechanism in retail gas rates to recover variations in gas supply and transportation costs. The PGA mechanism passes through to customers these variations in gas rates, and therefore PSE's gas margin and net income are not affected by changes in the PGA rates. The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2004, 2003 and 2002:

Effective Date	Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenues (Dollars In Millions)
October 1, 2004	17.6%	$121.7
October 1, 2003	13.3%	78.8
April 10, 2003	20.1%	103.6
November 1, 2002	(12.5)%	(70.6)
September 1, 2002	(7.3)%	(45.0)
June 1, 2002	(21.2)%	(138.9)

On February 18, 2005, the Washington Commission approved a 3.5% general tariff gas rate case increase to recover higher costs of providing natural gas service to customers. The rate increase will increase gas revenues by approximately $26.3 million annually, effective March 4, 2005. In the order, the Washington Commission also approved a capital structure containing 43% common equity with a return on common equity of 10.3%. In the proceeding, PSE had filed a request for an increase of 6.3% or $46.2 million annually on final rebuttal during the rate case for gas customers.

On August 28, 2002, the Washington Commission approved a 5.8% gas rate increase in general rates to recover higher costs of providing natural gas services to customers. The increase was intended to provide approximately $35.6 million annually in revenues. This rate increase became effective September 1, 2002.

UTILITY INDUSTRY OVERVIEW

FEDERAL REGULATION

Since the mid-1990s, FERC has required public utilities operating under the FPA to provide open access of their transmission systems to third parties under tariffs approved by FERC. There has been no material effect on the financial statements of PSE as a result of open access.

FERC Order No. 2000, issued on December 20, 1999, required all utilities subject to its jurisdiction that own, operate or control transmission facilities to either voluntarily form or participate in a Regional Transmission Organization (RTO); or, alternatively, describe its efforts to participate in an RTO or obstacles to such participation. PSE has been an active participant in regional efforts to form an RTO in the Pacific Northwest since issuance of Order No. 2000. Currently, PSE is working with nine other utilities on the formation of an RTO in the region known as Grid West. Any decision by PSE to participate in Grid West (or other RTO proposal) will depend on the ultimate form of the organization including terms and conditions for participation. Furthermore, any such decision will require approval of FERC, the Washington Commission and the boards of directors of the participating utilities. PSE cannot predict the outcome of efforts to form or participate in an RTO or whether any future decision to join (or not join) an RTO will have a material impact on the financial condition, results of operations or liquidity of the Company.

On July 31, 2002, FERC issued its Notice of Proposed Rulemaking on Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design (SMD NOPR). On April 28, 2003, FERC issued a white paper entitled “Wholesale Power Market Platform” (White Paper) that significantly modified the proposal outlined in the SMD NOPR. A modification of the wholesale electricity markets as provided in either the SMD NOPR or the White Paper would have major implications for the delivery of electric energy throughout the United States. Major elements of FERC’s proposal include: (a) a change to allow FERC to exercise jurisdiction over the non-rate terms and conditions for bundled retail sales, but leave the rate component under state jurisdiction; (b) require vertically integrated utilities to join an RTO or an Independent System Operator (ISO) to operate their transmission systems; and (c) require regions to develop an approach to manage congestion, encourage efficient use of the transmission grid and promote the use of the lowest cost generation. State regulators, congressional delegates and industry representatives have pointed out that the western North American electricity market has unique characteristics that may not readily lend itself to the market design proposed by FERC. In addition, Congress has proposed, but not passed, draft legislation that would require FERC to delay and reconsider its market design proposal. PSE cannot predict the outcome of the SMD NOPR or whether the ultimate resolution will have a material impact on the financial condition, results of operations or liquidity of the Company.

STATE REGULATION

The electric utility business in the State of Washington is fully regulated and provides service to its customers under cost-based tariff rates. PSE is not aware of any proposals or prospects for retail deregulation in the State of Washington.

Since 1986, PSE 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 independently obtain gas supply from third parties and transportation services directly from the interstate pipelines or other third parties. Although PSE has not lost any substantial industrial or commercial load as a result of such activities, in certain years up to 160 customers annually have taken advantage of unbundled transportation service. In 2004, 129 commercial and industrial customers, on average, chose to use such service. The shifting of customers between sales and transportation service does not materially impact utility margin, as PSE earns similar margins on transportation service as it does on large-volume, interruptible gas sales.

ELECTRIC OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	**2004**	**2003**	**2002**
Generation and purchased power, MWh			
Company-controlled resources	7,048,270	6,965,840	6,996,276
Contracted resources	9,421,546	11,021,471	12,085,729
Non-firm energy purchased[1]	6,164,457	5,179,302	4,795,045
Total generation and purchased power	22,634,273	23,166,613	23,877,050
Less: losses and company use	(1,432,686)	(1,338,401)	(1,341,126)
Total energy sales, MWh	21,201,587	21,828,212	22,535,924
Electric energy sales, MWh			
Residential	10,028,150	9,845,854	9,845,527
Commercial	8,449,566	8,222,166	8,012,538
Industrial	1,352,660	1,372,815	1,416,107
Other customers	94,034	93,438	90,840
Total energy billed to customers	19,924,410	19,534,273	19,365,012
Unbilled energy sales – net increase (decrease)	(40,217)	65,082	(102,811)
Total energy sales to customers	19,884,193	19,599,355	19,262,201
Sales to other utilities and marketers[1]	1,317,394	2,228,857	3,273,723
Total energy sales, MWh	21,201,587	21,828,212	22,535,924
Less: optimization purchases for sales to other utilities and marketers	--	(62,200)	(2,596,505)
Transportation, including unbilled	1,988,965	2,020,562	2,307,081
Net electric energy sales and transported, MWh	23,190,552	23,786,574	22,246,500

[1] *Non-firm energy purchased and Sales to other utilities and marketers in 2003 and 2002 were revised as a result of Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03" (EITF No. 03-11), which became effective January 1, 2004. MWh from other utility and marketers/non-firm energy purchased in 2003 and 2002 were reduced 2,941,707 MWh and 2,789,353 MWh, respectively.*

TWELVE MONTHS ENDED DECEMBER 31	2004	2003	2002
Electric operating revenues by classes (thousands):			
Residential	$ 628,869	$ 603,722	$ 616,522
Commercial	580,973	556,038	536,021
Industrial	88,779	88,201	90,121
Other customers	58,007	54,259	26,500
Operating revenues billed to customers[1]	1,356,628	1,302,220	1,269,164
Unbilled revenues – net increase (decrease)	(813)	4,193	(7,118)
Total operating revenues from customers	1,355,815	1,306,413	1,262,046
Transportation, including unbilled	10,707	11,542	15,551
Sales to other utilities and marketers[2]	56,512	84,994	75,595
Less: optimization purchases for sales to other utilities and marketers	--	(2,206)	(64,448)
Total electric operating revenues	$ 1,423,034	$ 1,400,743	$ 1,288,744
Number of customers served (average):			
Residential	874,205	854,088	839,878
Commercial	109,660	108,479	104,273
Industrial	3,953	3,952	3,953
Other	2,194	2,060	1,932
Transportation	17	16	16
Total customers (average)	990,029	968,595	950,052
Average retail revenues per kWh sold:			
Residential	$ 0.0627	$ 0.0617	$ 0.0632
Commercial	0.0688	0.0680	0.0675
Industrial	0.0656	0.0650	0.0649
Average retail revenue per kWh sold	0.0655	0.0646	0.0651
Average revenue billed to residential customers	$ 719	$ 711	$ 741
Average kWh used by residential customers	11,471	11,528	11,723
Heating degree days	4,421	4,527	4,946
Percent of normal – NOAA 30-year average	91.8%	94.4%	103.1%
Load factor	53.5%	58.9%	61.6%

1 *Operating revenues in 2004, 2003 and 2002 were reduced by $0.8 million, $7.7 million and $12.7 million, respectively, as a result of the Company's sale of $237.7 million of its investment in customer-owned conservation measures in 1995 and 1997. Beginning in July 2003, these related revenues were consolidated as a result of Financial Accounting Standards Board Interpretation No. 46. (See Operating Revenues-Electric in Management's Discussion and Analysis and Note 1 to the Consolidated Financial Statements.) As of October 2004, the conservation trust bond was fully redeemed and any excess collection was recorded as a reduction in revenues.*

2 *Sales to other utilities and marketers in 2003 and 2002 were revised as a result of Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03" (EITF No. 03-11), which became effective January 1, 2004. Revenues from other utilities and marketers in 2003 and 2002 were reduced by $108.7 million and $77.1 million, respectively*

ELECTRIC SUPPLY

At December 31, 2004, PSE's electric power resources were approximately 4,351 MW. PSE's historical peak load of approximately 4,847 MW occurred on December 21, 1998. In order to meet an extreme winter peak load, PSE supplements its electric power resources with winter-peaking call options and other instruments that may include, but are not limited to, weather-related hedges and exchange agreements. During 2004, PSE's total electric energy production was supplied 31.1% by its own resources, 23.1% through long-term contracts with several of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River, and 18.6% from other firm purchases. Short-term wholesale purchases, net of sales to other utilities and marketers, accounted for 22.7% of energy production in 2004.

The following table shows PSE's electric energy supply resources at December 31, 2004 and 2003, and energy production during the year:

	Peak Power Resources At December 31,				Energy Production			
	2004		2003		2004		2003	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts	1,350	31.0%	1,349	30.0%	5,231,691	23.1%	5,191,346	22.4%
Other hydroelectric[1]	177	4.1%	177	3.9%	600,557	2.7%	622,900	2.7%
Other producers[1]	1,011	23.2%	1,210	26.9%	3,589,298	15.9%	5,207,225	22.5%
Short-term wholesale energy purchases[2]	N/A	N/A	N/A	N/A	6,164,457	27.2%	5,179,302	22.4%
Total purchased	2,538	58.3%	2,736	60.8%	15,586,003	68.9%	16,200,773	70.0%
Company-controlled resources:								
Hydroelectric	234	5.4%	304	6.7%	1,130,180	5.0%	1,238,900	5.3%
Coal	677	15.6%	677	15.1%	5,119,002	22.6%	4,950,734	21.4%
Natural gas/oil	902	20.7%	778	17.4%	799,088	3.5%	776,206	3.3%
Total Company-controlled	1,813	41.7%	1,759	39.2%	7,048,270	31.1%	6,965,840	30.0%
Total	4,351	100.0%	4,495	100.0%	22,634,273	100.0%	23,166,613	100.0%

1 *Power received from other utilities is classified between hydroelectric 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.*

2 *Short-term wholesale purchases net of resales of 1,317,394 MWh and 2,228,857 MWh account for 22.7% and 14.1% of energy production for 2004 and 2003, respectively.*

Least Cost Plan

PSE filed its electric Least Cost Plan on April 30, 2003 with the Washington Commission. The plan supported a strategy of diverse electric power resource acquisitions including resources fueled by natural gas and coal, renewable resources (e.g. wind) and shared resources. A Least Cost Plan Update was filed in August 2003, which integrated efficiency programs into the resource mix. The Least Cost Plan was followed with the proposed acquisition of a gas combined-cycle combustion turbine, and the issuing of a wind resource Request for Proposal (RFP) in December 2003. An all-source RFP was issued in February 2004. PSE is in the process of updating its Least Cost Plan which is expected to be filed with the Washington Commission in the first half of 2005.

Based upon PSE's projected customer usage for electricity and its current electric generation resources, PSE projects that future energy needs will exceed current purchased and Company-controlled power resources. The projected MW shortfall at December 31, 2004 for the period 2006-2010 is as follows:

	2006	2007	2008	2009	2010
Projected MW Shortfall[1]	208	263	305	360	457

1 *Estimated using all resources under long-term contract and Company-controlled resources. Also includes anticipated acquisitions of the Hopkins Ridge and Wild Horse wind projects which are currently under review.*

PSE signed a non-binding letter of intent on October 29, 2004 to acquire a 100% interest in a 150 MW (52 average MW) wind powered electric generation facility to be developed in eastern Washington State. PSE anticipates spending up to $200 million on the project, which it will solely own once complete. This total includes approximately $180 million to acquire and construct the wind plant, $10 million to fund upgrades to the transmission systems of BPA and other regional transmission providers and approximately $10 million on financing and other costs. The proposed purchase transaction could occur as early as the end of the first quarter 2005, and if completed, construction on the project is anticipated to be completed sometime between late 2005 and mid 2006.

On September 1, 2004, PSE signed a second non-binding letter of intent to acquire a 100% interest in a 230 MW (77 average MW) wind powered electric generation facility to be developed in central Washington State. The estimated cost of the project is approximately $300 million, depending on design options. The proposed transaction is anticipated to be completed on or before January 1, 2006 and construction on the project is anticipated to be completed in 2006.

COMPANY – CONTROLLED ELECTRIC GENERATION RESOURCES

At December 31, 2004, PSE has the following plants with an aggregate net generating capacity of 1,813 MW:

PLANT NAME	PLANT TYPE	NET CAPACITY (MW)	YEAR INSTALLED
Colstrip Units 1 & 2 (50% interest)	Coal	307	1975 & 1976
Colstrip Units 3 & 4 (25% interest)	Coal	370	1984 & 1986
Fredonia Units 1 & 2	Dual-fuel combustion turbines	207	1984
Fredrickson Units 1 & 2	Dual-fuel combustion turbines	147	1981
Whitehorn Units 2 & 3	Dual-fuel combustion turbines	147	1981
Fredonia Units 3 & 4	Dual-fuel combustion turbines	107	2001
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	124	2002; Purchased 2004
Encogen	Natural gas cogeneration	167	1993
Crystal Mountain	Internal combustion	3	1969
Upper Baker River	Hydroelectric	91	1959
Lower Baker River	Hydroelectric	79	Reconstructed 1960; Upgraded 2001
Snoqualmie Falls	Hydroelectric	42	1898 to 1911 and 1957
Electron	Hydroelectric	22	1904 to 1929

COLSTRIP GENERATING FACILITY

In June 2004, PSE and Western Energy Company (WECO), the supplier of coal to Colstrip Units 1 & 2, entered into a binding arbitration and settled a dispute concerning prices paid for coal supplied. The binding decision retroactively set a new baseline cost per ton of coal purchased by PSE for Colstrip Units 1 & 2 supplied from July 31, 2001, and is applicable for the remaining term of the coal supply agreement through December 2009. The decision resulted in a $6.9 million charge that was recorded in the second quarter 2004. Of the $6.9 million charge, $5.0 million was included in the PCA mechanism. PSE had previously accrued a $1.6 million reserve in the fourth quarter 2003 related to the arbitration.

On April 29, 2004, the Minerals Management Service of the United States Department of the Interior (MMS) issued an order to WECO to pay additional royalties concerning coal purchased by PSE for Colstrip Units 3 & 4. The order seeks payment of an additional $1.1 million in royalties for coal mined from federal land between 1997 and June 30, 2000. During that period, PSE's coal price was reduced by a settlement agreement entered into in February 1997 among PSE, WECO and Montana Power Company that resolved disputes that were then pending. The order seeks to impute the price charged to PSE based on the other Colstrip Units 3 & 4 owners' contractual amounts. PSE is supporting WECO's appeal of the order, but is also evaluating the basis of the claim. PSE accrued a loss reserve in the amount of $1.1 million in connection with this matter in the second quarter 2004.

In addition, the MMS issued two orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 & 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 & 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. PSE's share of the alleged additional royalties is $1.8 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. Other parties may attempt to assert claims against WECO if the MMS position prevails. The transportation agreement provides for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip Units 3 & 4. WECO has appealed these orders and PSE is monitoring the process. PSE believes that the Colstrip Units 3 & 4 owners have reasonable defenses in this matter based upon its review. Neither the outcome of this matter nor the associated costs can be predicted at this time.

In September 2004, the owners of Colstrip Units 1 & 2 (PSE and PPL Montana) entered into a tentative settlement agreement with certain homeowners in the Colstrip town site area concerning a lawsuit filed in May 2003. In December 2004, the plaintiffs retained new counsel and postponed further settlement discussions until more discovery is completed. The lawsuit alleged certain domestic water wells may have been contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond. The tentative settlement agreement would require extending municipal water to the homeowners and abandoning the existing wells. The total estimated cost of the settlement ranges from $1.4 million to $1.5 million. As a result of this tentative settlement agreement, PSE recorded a $0.7 million reserve in the third quarter 2004 for its 50%

ownership of the Colstrip Units 1 & 2 project. The settlement agreement would not resolve certain other claims by residents within the city limits. PSE cannot predict the outcome or any potential financial impact of the claims by the residents within the city limits at this time.

FERC HYDROELECTRIC PROJECTS AND LICENSES

As part of its hydroelectric operations, PSE is required to obtain licenses from FERC. A typical license contains mandatory conditions of operation, such as flow rate requirements, adherence to certain ramping protocols for outages, maintenance of reservoir levels, equipment upgrade projects, and fish and wildlife mitigation projects. The licensing and relicensing processes involve harmonizing conflicting rights and obligations of numerous governmental, non-governmental and private parties, and dealing with issues that may include environmental compliance, fish protection and mitigation, water quality, Native American rights, title claims, operational and capital improvements, and flood control. As a result, a number of political, compliance and financial risks can arise from the licensing and relicensing processes.

PSE owns three hydroelectric projects: the Baker River project, the Snoqualmie Falls project and the Electron project. The White River project ceased operations as a hydroelectric generating resource in January 2004. The Baker River and Snoqualmie Falls projects are operating under the jurisdiction of FERC. FERC regulates dam safety and administers proceedings under the FPA to license jurisdictional hydropower projects. FERC licenses are generally issued for a term of 30 to 50 years.

Baker River project. The Baker River project consists of the Lower Baker Development (constructed in 1925) and the Upper Baker Development (constructed in 1959). The Baker River project's current license expires on April 30, 2006, and PSE submitted an application for a new license to FERC on April 30, 2004. On November 30, 2004, PSE and 23 parties comprised of federal, state and local governmental organizations, Native American Indian tribes, environmental and other nongovernmental entities filed a proposed comprehensive settlement agreement on all issues relating to the relicensing of the Baker River project. The proposed settlement includes a set of proposed license articles and, if approved by FERC without material modification, would allow a new license for 45 years or more. The proposed settlement would require an investment of approximately $360 million (capital expenditures and operations and maintenance cost) in order to implement the conditions of the new license over the next 30 years. The proposed settlement is subject to contingencies that have yet to be resolved and is subject to additional regulatory approvals yet to be attained from various agencies. FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain. Assuming that settlement contingencies are resolved and additional regulatory approvals are obtained in a timely manner and on favorable terms, a decision by FERC could occur by April 2006.

Snoqualmie Falls project. The Snoqualmie Falls project, built in 1898, had its original license issued May 13, 1975, which was made effective retroactive to March 1, 1956, and expired on December 31, 1993. PSE filed its application to relicense the project on November 25, 1991, and operated the project pursuant to annual licenses issued by FERC since the original license expired. On June 29, 2004, FERC granted PSE a new 40-year operating license for the Snoqualmie Falls project. PSE estimates that the investment required to implement the conditions of the new license agreement will cost approximately $44 million. These conditions include modified operating procedures and various project upgrades that include better protection of fish, development of riparian habitat to promote fish propagation, increased minimum flows in the Snoqualmie River during low-water periods and the development of recreational amenities near the down-river power house. On July 29, 2004, the Snoqualmie Tribe and certain other parties filed a request for rehearing of the new license and a request to stay the FERC license. FERC has not ruled on this request and the outcome remains uncertain. In the meantime, because a stay has not been issued, the Company is proceeding with its plan of rehabilitation necessary to comply with the terms of the new license.

Electron project. The Electron project was built in 1904. The project's capacity is currently 22 MW. In 1977, the project was determined to be a "pre-1935" project under the FPA and therefore not subject to FERC jurisdiction. In this status, the project can continue to operate without a FERC license absent "post-1935" construction of a nature sufficient to invoke FERC's jurisdiction. PSE does not anticipate undertaking any betterments or improvements to the project that would entail "post-1935" construction.

The project also operates in compliance with the terms and conditions of a "Resource Enhancement Agreement" with the Puyallup Indian Tribe. This agreement resolved the Tribe's long-standing claims for resource and other damages allegedly associated with the construction and operation of the project. The agreement also provides that in 2018 PSE must decide to either retire the project by 2026 or, in lieu of retirement, undertake significant upgrades that would likely invoke FERC jurisdiction. The outcome of these deliberations is not expected to have a material impact upon the financial condition, results of operations or liquidity of the Company.

White River project. The White River project was built in 1911 and was operated as a hydropower facility until January 15, 2004. PSE submitted a license application to FERC in 1983, and in December 1997, FERC issued a proposed license for the project. PSE appealed the 1997 license because it contained terms and conditions that would render ongoing operations of the project uneconomic relative to alternative resources. In November 2003, PSE determined that it could no longer continue to economically operate the project due to additional conditions primarily related to two listings under the Endangered Species Act. On December 23, 2003, PSE notified FERC that it rejected the 1997 license for the White River project and on January 15, 2004, generation of electricity ceased at the White River project. PSE is actively seeking to sell the project to one or more entities interested in maintaining the reservoir for commercial purposes.

In the PCORC Order issued on April 7, 2004, the Washington Commission approved PSE's recovery on the unamortized White River plant investment. At December 31, 2004, the White River project net book value totaled $65.1 million, which included $46.4 million of net utility plant, $14.8 million of capitalized FERC licensing costs, $3.1 million of costs related to construction work in progress, and $0.8 million related to dam operations and safety. PSE sought recovery of the relicensing, other construction work in progress and dam operations and safety costs totaling $18.7 million in its general rate filing of April 2004, over a 10-year amortization period. In the third quarter 2004, the Washington Commission staff recommended that PSE be allowed recovery of the White River net utility plant costs noted above, but defer any amortization of the FERC licensing and other costs until all costs and any sales proceeds are known. In its February 18, 2005 general rate case order, the Washington Commission found this treatment reasonable, and adopted all of the staff recommendations.

In January 2001, certain environmental groups gave notice of their intent to sue for alleged violations of the Endangered Species Act, but no such lawsuit has been filed. In May 2004, the Puyallup Indian Tribe gave PSE notice of intent to sue for an alleged violation of water quality laws associated with the release of water from the White River project reservoir. No such lawsuit has been filed and PSE is in discussion with the Puyallup Indian Tribe regarding their concerns. Additionally, PSE has sought, and is awaiting, further direction from the Washington State Department of Ecology (Ecology) as to whether any additional actions are necessary to maintain compliance with applicable water quality laws.

Homeowners and others interested in preserving the project reservoir (Lake Tapps) have expressed concern over the possible loss of the reservoir and there has been a solicitation of interest in a potential lawsuit against PSE to preserve the reservoir, but no such lawsuit has been filed to date.

In September 2004, the Company renewed its contract with the United States Army Corps of Engineers (COE) to maintain operation of the White River diversion dam to support the COE's ongoing operation of its Mud Mountain Dam fish passage facilities. The agreement provides for reimbursement of a portion of PSE's operating costs and directs PSE to operate the diversion dam in accordance with measures determined by federal agencies to be necessary to protect listed species and habitat. This contract expires in September 2005, although the COE has expressed its desire to extend the term for a period of time necessary to allow the COE to develop a plan to acquire the diversion dam from the Company.

In June 2003, Ecology approved an application for new municipal water rights related to the White River project reservoir. This approval was sought in connection with PSE's ongoing efforts to sell the White River project to be used for commercial purposes. An appeal of Ecology's decision approving the new municipal water rights was subsequently filed with the Washington State Pollution Control Hearings Board. In July 2004, this decision was remanded back to Ecology for further analysis of non-hydropower operations. The Company has been advised by Ecology that Ecology anticipates issuing a revised decision by the end of 2005; however, no firm date has been set for any such revised decision. Any proceeds from the sale of the White River water rights will reduce the balance of the deferred regulatory asset. Neither the outcome of this matter nor any potential associated costs can be predicted at this time.

COLUMBIA RIVER ELECTRIC ENERGY SUPPLY CONTRACTS

During 2004, approximately 23.1% of PSE's energy output was obtained at an average cost of approximately $0.0146 per kWh through long-term contracts with several of the Washington PUDs that own and operate hydroelectric projects on the Columbia River. PSE's purchases of power from the Columbia River projects are on a "cost of service" basis under which PSE pays a proportionate share of the annual debt service and operating and maintenance costs of each project in proportion to the contractual shares that PSE has rights to from such project. Such payments are not contingent upon the projects being operable, which means PSE is required to make the payments even if power is not being delivered. 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 repairs, replacements, license requirements, or changes to annual operating and maintenance expenses are required.

PSE has contracted to purchase from Chelan County PUD (Chelan) a 50% share of the output of the original units of the Rock Island project, which percentage will remain unchanged for the duration of the contract which expires in 2012. PSE has also contracted to purchase the output of the additional Rock Island units for the duration of the contract. As of December 31, 2004, PSE's aggregate capacity from all units of the Rock Island project was 413.9 MW. PSE's share of output of the additional Rock Island units may be reduced by up to 10% per year. On July 1, 2000, Chelan began withdrawing 5% of the power from the additional Rock Island units for use in meeting its local load. The maximum withdrawal that Chelan may make from the additional units is 50%. The schedule of withdrawals by Chelan for the additional Rock Island units is as follows:

Date of Withdrawal	Withdrawal Percentage	PSE % of Capacity after Withdrawal
February 1, 2005	10%	65%
July 1, 2005	10%	55%
November 1, 2006	5%	50%

PSE has contracted to purchase from Chelan 38.9% (505 MW of peak capacity as of December 31, 2004) of the annual output of the Rocky Reach project, which percentage remains unchanged for the remainder of the contract which expires in 2011.

PSE has contracted to purchase from Douglas County PUD 31.3% (261 MW as of December 31, 2004) of the annual output of the Wells project, the percentage of which remains unchanged for the remainder of the contract which expires in 2018. Early in 2003, the Colville Confederated Tribes (Colville Tribe) presented a claim to Douglas County PUD based upon allegedly unpaid past annual charges for the Wells Hydroelectric project for the use of Colville Tribal lands. The Colville Tribe also claimed that annual charges would be due for periods into the future. On November 1, 2004, Douglas County PUD entered into a settlement with the Colville Tribe concerning claims that the Colville Tribe had asserted against Douglas County PUD for the use by the Wells project of Tribal lands. PSE approved the settlement and participated in the filing Douglas County PUD made on November 23, 2004 seeking FERC approval. The settlement was approved in a FERC order on February 11, 2005. It is unlikely that any party will seek a rehearing of that FERC order, of which the deadline for doing so is March 13, 2005. When the settlement becomes final, the effects on PSE will be through modestly increased power costs, and a reduction in the amount of power delivered to PSE due to the allocation to the Colville Tribe. The Colville Tribe's allocation will be treated as an encroachment to the project, thus reducing the amount of power available for purchase by others.

PSE has contracted to purchase from Grant County PUD 8.0% (72 MW as of December 31, 2004) of the annual output of the Priest Rapids Development and 10.8% (98 MW of peak capacity as of December 31, 2004) of the annual output of the Wanapum Development, which percentages remain unchanged for the remainder of the original contract terms which expire in 2005 and 2009, respectively. On December 28, 2001, PSE signed a contract offer for new contracts for the Priest Rapids and Wanapum Developments. On April 12, 2002, PSE signed amendments to those agreements which are technical clarifications of certain sections of the agreements. Under the terms of these contracts, PSE will continue to obtain capacity and energy for the term of any new FERC license to be obtained by Grant County PUD. Grant County PUD filed an application for new license for the Priest Rapids project on October 29, 2003. The new contracts' terms begin in November 2005 for the Priest Rapids Development and in November 2009 for the Wanapum Development. Unlike the current contracts, in the new contracts, PSE's share of power from the developments declines over time as Grant County PUD's load increases.

On March 8, 2002, the Yakama Nation filed a complaint with FERC which alleged that Grant County PUD's new contracts unreasonably restrain trade and violate various sections of the FPA and Public Law 83-544. On November 21, 2002, FERC dismissed the complaint while agreeing that certain aspects of the complaint had merit. As a result, FERC has ordered Grant County PUD to remove specific sections of the contract which constrain the parties to the Grant County PUD contracts from competing with Grant County PUD for a new license. A rehearing was requested but was denied by

FERC on April 16, 2003. Both the Yakama Nation and Grant County PUD have appealed the FERC decision and the appeals have been consolidated in the Ninth Circuit Court of Appeals.

ELECTRIC ENERGY SUPPLY CONTRACTS AND AGREEMENTS WITH OTHER UTILITIES

PSE has entered into long-term firm purchased power contracts with other utilities in the West region. PSE is generally not obligated to make payments under these contracts unless power is delivered.

Under a 1985 settlement agreement with BPA relating to Washington Public Power Supply System Nuclear Project No. 3 (WNP-3), in which PSE had a 5 percent interest, PSE is entitled to receive exchange energy from BPA during the months of November through April. The power PSE receives, which amounts to 47 average MW of energy and 82 MW of capacity for contract year 2004-2005, is tied to the equivalent annual availability factor of several surrogate nuclear plants similar in design to WNP-3. BPA has an option to request that PSE deliver up to 63 MW of exchange energy to BPA in all months except May, July and August for contract year 2004 – 2005. The contract terminates June 30, 2017, but may be ended earlier if the number of surrogate operating years of the longest running surrogate unit is less than 30 years.

On October 1, 1989, PSE signed a contract with The Montana Power Company, which subsequently sold its utility assets to NorthWestern Corporation (NorthWestern) in 2002. Under the contract, NorthWestern provides PSE 71 average MW of energy (97 MW of peak capacity) over a 21-year period. This contract expires in December 2010. On November 1, 2004 NorthWestern emerged from bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. PSE has several long-term contracts with NorthWestern under which PSE jointly owns facilities or purchases power or transmission services from NorthWestern. During the bankruptcy proceeding NorthWestern affirmed its continued performance under all of these agreements.

In January 1992, PSE executed an exchange agreement with Pacific Gas & Electric Company (PG&E). Under the agreement, 300 MW of capacity together with up to 413,000 MWh of energy are exchanged seasonally each year. No payments are made under this agreement. PG&E is a summer peaking utility and provides power during the months of November through February. PSE is a winter peaking utility and provides power during the months of June through September. Each party may terminate the contract upon notifying the other party at least five years in advance.

In February 1996, a 10-year power exchange agreement between PSE and Powerex (a subsidiary of a British Columbia, Canada utility) became effective. Under this agreement, Powerex pays PSE for the right to deliver up to 1,200,000 MWh annually to PSE at the Canadian border in exchange for PSE delivering power to Powerex at various locations in the United States. The agreement also allows Powerex to make up any exchange volumes not used up to two years after the end of the annual period.

ELECTRIC ENERGY SUPPLY CONTRACTS AND AGREEMENTS WITH NON-UTILITY GENERATORS

As required by the federal Public Utility Regulatory Policies Act, PSE has entered into long-term firm purchased power contracts with non-utility generators. The most significant of these are the contracts described below which PSE entered into in 1989, 1990, and 1991 with operators of natural gas-fired cogeneration projects. PSE purchases the net electrical output of these three projects at fixed and annually escalating prices, which were intended to approximate PSE’s avoided cost of new generation projected at the time these agreements were made.

On February 24, 1989, PSE 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, LP, which owns and operates a natural gas-fired cogeneration project located in Sumas, Washington.

On June 29, 1989, PSE 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 the Equilon refinery in Anacortes, Washington. On December 27, 1990, PSE 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 Equilon refinery in Anacortes, Washington.

On March 20, 1991, PSE 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, LP, which owns and operates a natural gas-fired cogeneration project located near Ferndale, Washington. In December 1997 and January 1998, PSE and Tenaska Washington Partners entered into revised agreements in which PSE 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. PSE obtained an order from the Washington Commission creating a regulatory asset related to the $215 million restructuring payment. Under terms of the order, PSE was allowed to accrue as an additional regulatory asset one-half the carrying costs of the deferred balance over the first five years, which ended December 2002. The balance of the regulatory asset at December 31, 2004 was $202.0 million, which will be recovered in electric rates through 2011.

In December 1999, PSE bought out the remaining 8.5 years of one of the natural gas supply contracts serving Encogen from Cabot Oil & Gas Corporation (Cabot) which provided approximately 60% of the plant's natural gas requirements. PSE became the replacement gas supplier to the project for 60% of the supply under the terms of the Cabot agreement. The balance of the regulatory asset at December 31, 2004 was $9.3 million, which will be recovered in electric rates through 2008.

ELECTRIC TRANSMISSION CONTRACTS WITH OTHER UTILITIES

PSE has entered into numerous transmission contracts with BPA to integrate electric generation resources and energy contracts into the PSE system to serve native load. These transmission contracts specify that PSE will pay for transmission service based on the contracted megawatt level of demand, regardless of actual use. Other agreements, notably the Westside Northern Intertie Agreement and the AC Intertie Capacity Ownership Agreement provide capacity ownership type rights to PSE. PSE's annual charges are also based on contracted megawatt amounts. Capacity on these agreements that are not committed for native load or other uses are available for sale to third parties on PSE's Open Access Same Time Information System (OASIS). PSE purchases short term transmission services from a variety of providers, including BPA.

The transmission agreements with BPA provide, among other things, the integration of PSE's energy resources including PSE's share of the Mid-Columbia hydroelectric projects, the Colstrip project and the PG&E exchange. The agreements have various terms ranging from specified dates in the 1 to 14 year time frame to life-of-facilities, the latter being in effect as long as the transmission facilities themselves are fully functional. Collectively, the agreements have an aggregate demand limit in excess of 2,200 MW.

In April 2004, PSE entered into a two-year contract with BPA to integrate the output of PSE's recently acquired share of the Frederickson 1 plant. The hourly demand limit of this contract is 150 MW.

PSE's transmission expenses for integrating its firm resources was $34.7 million in 2004. The transmission rates used by BPA for these contracts are effective through September 30, 2005. BPA rates change from time to time based upon BPA's rate cases.

On December 6, 2004, BPA offered a proposed transmission rate case settlement agreement to BPA's transmission customers. Under the terms of the settlement agreement, the BPA IR Rate, the rate at which PSE receives the vast majority of its transmission service from BPA, will increase 17.6%. On January 6, 2005, BPA reached settlement with all its customers. BPA must file the settlement agreement with FERC and wait for FERC's approval before rates can go into effect. It is anticipated that rates will go into effect October 1, 2005.

GAS OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	2004	2003	2002
Gas operating revenues by classes (thousands):			
Residential	$ 478,969	$ 401,717	$ 428,569
Commercial firm	187,262	149,671	167,434
Industrial firm	30,472	24,164	28,312
Interruptible	46,900	34,046	48,889
Total retail gas sales	743,603	609,598	673,204
Transportation services	12,968	13,796	12,851
Other	12,735	10,836	11,100
Total gas operating revenues	$ 769,306	$ 634,230	$ 697,155
Number of customers served (average):			
Residential	605,505	583,439	565,003
Commercial firm	48,457	46,813	45,916
Industrial firm	2,678	2,685	2,727
Interruptible	576	611	650
Transportation	129	134	122
Total customers	657,345	633,682	614,418
Gas volumes, therms (thousands):			
Residential	489,036	500,116	500,672
Commercial firm	217,346	216,951	218,716
Industrial firm	36,751	36,890	39,142
Interruptible	65,425	61,739	81,045
Total retail gas volumes, therms	808,558	815,696	839,575
Transportation volumes	201,642	209,497	207,852
Total volumes	1,010,200	1,025,193	1,047,427
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	70,986	60,365	64,583
Clay Basin	55,044	49,314	51,225
Average therms used per customer:			
Residential	808	857	886
Commercial firm	4,485	4,634	4,763
Industrial firm	13,723	13,739	14,354
Interruptible	113,585	101,046	124,685
Transportation	1,563,116	1,563,410	1,703,705
Average revenue per customer:			
Residential	$ 791	$ 689	$ 759
Commercial firm	3,864	3,197	3,647
Industrial firm	11,379	9,000	10,382
Interruptible	81,424	55,722	75,214
Transportation	100,527	102,955	105,336
Average revenue per therm sold:			
Residential	$ 0.979	$ 0.803	$ 0.855
Commercial firm	0.862	0.690	0.766
Industrial firm	0.829	0.655	0.723
Interruptible	0.717	0.551	0.603
Average retail revenue per therm sold	0.920	0.747	0.802
Transportation	0.064	0.066	0.062

GAS SUPPLY

PSE currently purchases a blended portfolio of gas supplies ranging from long-term firm to daily gas supplies from a diverse group of major and independent natural gas producers and marketers in the United States and Canada. PSE also enters into short-term physical and financial fixed price derivative instruments to hedge the cost of gas to serve its customers. All of PSE's gas supply is ultimately transported through the facilities of Williams Northwest Pipeline Corporation (NWP), the sole interstate pipeline delivering directly into the western Washington area. Delivery of gas supply to PSE's gas system is therefore dependent upon the operations of NWP.

PEAK FIRM GAS SUPPLY AT DECEMBER 31	2004 Dth per Day	%	2003 Dth per Day	%
Purchased gas supply:				
British Columbia	198,000	22.7%	171,000	20.0%
Alberta	50,000	5.7%	78,000	9.2%
United States	145,000	16.6%	100,000	11.7%
Total purchased gas supply	393,000	45.0%	349,000	40.9%
Purchased storage capacity:				
Clay Basin	48,000	5.5%	55,800	6.5%
Jackson Prairie	55,100	6.3%	55,100	6.4%
LNG	70,500	8.1%	70,500	8.2%
Total purchased storage capacity	173,600	19.9%	181,400	21.1%
Owned storage capacity:				
Jackson Prairie	294,700	33.7%	294,700	34.4%
Propane-air and other	12,500	1.4%	30,500	3.6%
Total owned storage capacity	307,200	35.1%	325,200	38.0%
Total peak firm gas supply	873,800	100.0%	855,600	100.0%
Other and commitments with third parties	(53,100)		(53,200)	
Total net peak firm gas supply	820,700		802,400	

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

For baseload and peak-shaving purposes, PSE supplements its firm gas supply portfolio by purchasing natural gas, injecting it into underground storage facilities and withdrawing it during the peak winter heating season. Storage facilities at Jackson Prairie in western Washington and at Clay Basin in Utah are used for this purpose. Jackson Prairie is also used for daily balancing of load requirements on PSE's gas system. PSE has been in the process of expanding the storage capacity at Jackson Prairie since March 2003, and plans to continue doing so through 2008. At the end of this project, PSE will have added approximately 2,000,000 Dekatherms (one Dekatherm, or Dth, is equal to one million British thermal units or MMBtu) of additional working storage capacity. Peaking needs are also met by using PSE-owned gas held in NWP's liquefied natural gas (LNG) facility at Plymouth, Washington, by producing propane-air gas at a plant owned by PSE and located on its distribution system, and by interrupting service to customers on interruptible service rates.

PSE 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. PSE believes it will be able to acquire incremental firm gas supply to meet anticipated growth in the requirements of its firm customers for the foreseeable future.

GAS SUPPLY PORTFOLIO

For the 2004-2005 winter heating season, PSE contracted for approximately 22.7% of its expected peak-day gas supply requirements from sources originating in British Columbia, Canada under a combination of long-term, medium-term and seasonal purchase agreements. Long-term gas supplies from Alberta represent approximately 5.7% of the peak-day requirements. Long-term and winter peaking arrangements with U.S. suppliers make up approximately 16.6% of the peak-day portfolio. The balance of the peak-day requirements is expected to be met with gas stored at Jackson Prairie, gas stored at Clay Basin, LNG held at NWP's Plymouth facility and propane-air and other resources, which represent approximately 40.0%, 5.5%, 8.1% and 1.4%, respectively, of expected peak-day requirements. PSE also has the ability to curtail service to industrial and commercial customers on interruptible service rates during a peak-day event.

During 2004, approximately 32% of gas supplies purchased by PSE originated in British Columbia while 20% originated in Alberta and 48% originated in the United States. The current firm, long-term gas supply portfolio consists of arrangements with 12 producers and gas marketers, with no single supplier representing more than 4% of expected peak-day requirements. Contracts have remaining terms ranging from less than one year to ten years.

PSE's firm gas supply portfolio has flexibility in its transportation arrangements so that some savings can be achieved when there are regional price differentials between gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing gas supplies during off-peak periods to minimize costs. Gas is marketed outside PSE's service territory (off-system sales) whenever on-system customer demand requirements permit.

GAS STORAGE CAPACITY

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground gas storage facilities adjacent to NWP's pipeline. These facilities represent 45.5% of the expected peak-day portfolio. The Jackson Prairie facility, operated and one-third owned by PSE, is used primarily for intermediate peaking purposes since it is able to deliver a large volume of gas over a relatively short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE has peak firm delivery capacity of over 349,000 Dth per day and total firm storage capacity exceeding 8,100,000 Dth at the facility. The location of the Jackson Prairie facility in PSE's market area increases supply reliability and provides significant pipeline demand cost savings by reducing the amount of annual pipeline capacity required to meet peak-day gas requirements. The Clay Basin storage facility is a supply area storage facility that is used primarily to reduce portfolio costs through injections and withdrawals that take advantage of market price volatility and is also used for system reliability. After the release of capacity in 2004, PSE retained maximum firm withdrawal capacity of over 60,000 Dth per day from the Clay Basin facility with total storage capacity of almost 7,419,000 Dth. The Clay Basin capacity is held under two long-term contracts with remaining terms of 8 and 15 years. The capacity release contracts PSE has with multiple parties at the Clay Basin storage facility have remaining terms of three months as of December 31, 2004, with automatic renewal for 12-month terms. PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin is over 110,000 Dth per day and exceeds 13,000,000 Dth, respectively, when PSE has not released any of the capacity.

LNG AND PROPANE-AIR RESOURCES

LNG and propane-air resources provide gas supply on short notice for short periods of time. Due to their typically high cost, these resources are normally utilized as the supply of last resort in extreme peak-demand periods, typically lasting a few hours or days. PSE has a long-term contract for storage of 241,700 Dth of PSE-owned gas as LNG at NWP's Plymouth facility, which equates to approximately three and one-half days supply at a maximum daily deliverability of 70,500 Dth. PSE owns storage capacity for approximately 1.5 million gallons of propane. The propane-air injection facilities are capable of delivering the equivalent of 10,000 Dth of gas per day for up to twelve days directly into PSE's distribution system.

In 2004, a 6,000 Dth capacity LNG storage facility was completed in Gig Harbor. The purpose of the facility is to provide a supplemental supply of natural gas during periods of high demand, improve overall system reliability and eliminate the need for portable LNG operations in the Gig Harbor area. Included in the facility are a transport trailer, storage tank, transfer station and send out skid.

GAS TRANSPORTATION CAPACITY

PSE currently holds firm transportation capacity on pipelines owned by NWP, Gas Transmission Northwest, TransCanada Pipelines, Ltd. (TransCanada), and Duke Energy Gas Transmission (Westcoast). Accordingly, PSE 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.

PSE and WNG CAP I, a wholly-owned subsidiary of PSE, hold firm year-round capacity on NWP through various contracts. PSE and WNG CAP I participate in the secondary pipeline capacity market to achieve savings for PSE's customers. As a result, PSE and WNG CAP I hold approximately 465,000 Dth per day of capacity due to capacity release and segmentation transactions on NWP that provides firm delivery to PSE's service territory. In addition, PSE holds approximately 413,000 Dth per day of seasonal firm capacity on NWP to provide for delivery of stored gas during the heating season. PSE has firm transportation capacity on NWP that supplies the Frederickson 1 generating facility of approximately 22,000 Dth per day, with a remaining term of 14 years. PSE has released certain segments of its firm capacity with third parties to effectively lower transportation costs. PSE's firm transportation capacity contracts with NWP have remaining terms ranging from less than 1 year to 12 years. However, PSE 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. PSE's firm transportation capacity on Gas Transmission Northwest's pipeline, totaling approximately 90,000 Dth per day, has a remaining term of 19 years.

PSE's firm transportation capacity on Westcoast's pipeline, totaling approximately 40,000 Dth per day, has a remaining term of 10 years for approximately 25,000 Dth per day and a remaining term of 14 years for approximately 15,000 Dth per day. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the Frederickson 1 generating facility, totaling approximately 22,000 Dth per day, with a remaining term of 10 years. PSE's firm capacity on TransCanada's Alberta and British Columbia transportation systems, totaling approximately 80,000 Dth per day, phases in year to year renewal rights beginning in 2006. In addition, PSE has firm transportation capacity on TransCanada's pipelines commencing in 2008 with a term of 15 years, totaling approximately 8,000 Dth per day.

During 2003, NWP took one of its two parallel pipelines serving western Washington from British Columbia out of service as a result of a second failure of the affected pipeline. Together, these two pipelines had the ability to flow approximately 1,300,000 Dth per day of gas from British Columbia. The loss of the affected pipeline reduced this ability to approximately 950,000 Dth per day. Subsequent to testing and remediation efforts, portions of the affected line were returned to service in 2004, increasing the ability to flow gas from British Columbia to approximately 1,100,000 Dth per day. If the affected pipeline is not completely returned to service, the loss could potentially decrease PSE's overall NWP capacity by 5%. In December 2004, NWP filed a request for authorization from FERC to replace all of the lost capacity through construction of new facilities. NWP expects to complete such Capacity Replacement project by the end of 2006. The cost of the Capacity Replacement project is expected to increase the cost for services that PSE receives from NWP by approximately 20% beginning in 2007. PSE expects that the increase will be entirely recoverable from customers through the existing PGA mechanism. To date, the loss of capacity has not adversely impacted PSE's ability to serve its gas customers, but customers on interruptible tariff rate schedules could be curtailed during peak events. PSE expects to continue meeting its customer needs throughout the pipeline capacity replacement period, and PSE has back-up oil supply for its combustion turbines.

CAPACITY RELEASE

FERC provided a capacity release mechanism as the means for holders of firm pipeline and storage entitlements to temporarily relinquish 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. PSE continues to successfully mitigate a portion of the demand charges related to both storage and NWP pipeline capacity not utilized during off-peak periods through capacity release. WNG CAP I was formed to provide additional flexibility and benefits from capacity release. Capacity release benefits are passed on to customers through the PGA mechanism.

ENERGY EFFICIENCY

PSE offers programs designed to help new and existing customers use energy efficiently. PSE uses a variety of mechanisms including cost-effective financial incentives, 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, PSE has recovered electric energy efficiency (or conservation) expenditures through a tariff rider mechanism. The rider mechanism allows PSE to defer the efficiency expenditures and amortize them to expense as PSE concurrently collects the efficiency expenditures in rates over a one-year period. As a result of the rider, electric energy efficiency expenditures have no effect on earnings.

Since 1995, PSE has been authorized by the Washington Commission to defer gas energy efficiency (or conservation) expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows PSE to defer efficiency expenditures and recover them in rates over the subsequent year. The tracker mechanism also allows PSE to recover an Allowance for Funds Used to Conserve Energy on any outstanding balance that is not being recovered in rates. As a result of the tracker mechanism, gas energy efficiency expenditures have no impact on earnings.

Energy efficiency programs reduce customer consumption of energy thus impacting energy margins. The impact of load reductions are adjusted in rates at each general rate case.

ENVIRONMENT

The Company's operations are subject to environmental laws and 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 23 to the Consolidated Financial Statements for further discussion of environmental sites.)

REGULATION OF EMISSIONS

PSE has an ownership interest in coal-fired, steam-electric generating plants at Colstrip, Montana, which are subject to regulation of emissions and other regulatory requirements. PSE also owns combustion turbine units in western Washington, which are capable of being fueled by natural gas or diesel fuel. These combustion turbines are operated to comply with emission limits set forth in their respective air operating permits.

There is no assurance that in the future, environmental regulations affecting sulfur dioxide, carbon monoxide particulate matter or nitrogen oxide emissions may not be further restricted, or that restrictions on greenhouse gas emissions, such as carbon dioxide, or other combustion byproducts, such as mercury, may not be imposed.

In December 2003, Colstrip Units 1 & 2 and 3 & 4 received an information request from the Environmental Protection Agency (EPA) relating to their compliance with the Clean Air Act New Source Review regulations. PSE is currently in discussions with the EPA concerning the information request. Neither the outcome of this matter nor any potential associated costs can be predicted at this time

FEDERAL ENDANGERED SPECIES ACT

Since the 1991 listing of the Snake River Sockeye salmon as an endangered species, a total of eight species of salmon and steelhead have been listed as endangered species, which influences operations. Most directly associated with project operations, the Upper Columbia River Steelhead and the Upper Columbia Spring Chinook were listed as endangered species by the National Marine Fisheries Service in August 1997 and March 1999, respectively. To address this exposure, the Mid-Columbia PUDs initiated consultation with federal and state agencies, Native American tribes and non-governmental organizations to secure operational protection through long-term settlements and habitat conservation plans (HCPs) for each affected project. The agreement provisions include fish protection and enhancement measures for the next 50 years. The HCPs received the support of the resource agencies, have been adopted by FERC and generally obligate 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 reached an agreement with the various parties in 2004 in a form substantially similar to the HCPs adopted by Douglas County PUD and Chelan County PUD. FERC issued an order approving that settlement and terminating the Mid-Columbia fish proceeding as to all parties on December 16, 2004.

The proposed listings of Puget Sound Chinook salmon and spring Chinook salmon as endangered species for the upper Columbia River were approved in March 1999. The Company does not expect the listing of spring Chinook salmon as an endangered species for the upper Columbia River to result in markedly differing conditions for operations from previous listings in the area.

The completed listings of Coastal/Puget Sound Distinct Population Segment of Bull Trout as an endangered species in the fall of 1999 and Puget Sound Chinook salmon in the winter of 2001 are causing a number of changes to operations of governmental agencies and private entities in the region, including PSE. These changes may adversely affect hydroelectric plant operations and permit issuance for facilities construction, and increase costs for processes and facilities. Because PSE relies substantially less on hydroelectric energy from the Puget Sound area than from the Mid-Columbia River and also because the impact on PSE operations in the Puget Sound area is not likely to impair significant generating resources, the impact of listing for Puget Sound Chinook salmon and Bull Trout, while potentially representing cost exposure and operational constraints, should be proportionately less than the effects of the Columbia River listings. PSE is actively engaging the federal agencies to address Endangered Species Act issues for PSE's generating facilities. Consultation with federal agencies is ongoing.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Puget Energy as of December 31, 2004 are listed below. Puget Energy considers the Chief Executive Officer of InfrastruX to be an executive officer of Puget Energy. For their business experience during the past five years, please refer to the table below regarding Puget Sound Energy's executive officers. Officers of Puget Energy are elected for one-year terms.

NAME	AGE	OFFICES
S. P. Reynolds	56	President and Chief Executive Officer since January 2002. Director since January 2002.
J. W. Eldredge	54	Corporate Secretary and Chief Accounting Officer since April 1999.
D. E. Gaines	47	Vice President Finance and Treasurer since March 2002.
M. T. Lennon	42	President and Chief Executive Officer of InfrastruX since April 2003, President of InfrastruX, 2002 – 2003. Prior to joining InfrastruX, he served as Managing Director of Lennon Smith Advisors, LLC, an investment banking firm, 2000 – 2002.
J. L. O'Connor	48	Vice President and General Counsel since January 2003.
B. A. Valdman	41	Senior Vice President Finance and Chief Financial Officer since January 2004.

The executive officers of Puget Sound Energy as of December 31, 2004 are listed below along with their business experience during the past five years. Officers of Puget Sound Energy are elected for one-year terms.

NAME	AGE	OFFICES
S. P. Reynolds	56	President and Chief Executive Officer and Director since January 2002; President and Chief Executive Officer of Reynolds Energy International, 1998 – 2002.
D. P. Brady	40	Vice President Customer Services since February 2003; Director and Assistant to Chief Operating Officer, 2002 – 2003. Prior to joining PSE, he was Managing Director of Irvine Associates Merchant Banking Group, 2001 – 2002; Executive Vice President-Operations of Orcom Solutions, 2000 – 2001.
P. K. Bussey	48	Vice President Regional and Public Affairs since September 2003. Prior to joining PSE, he was President of the Washington Round Table, 1996 – 2003.
J. W. Eldredge	54	Vice President, Corporate Secretary, Controller and Chief Accounting Officer since May 2001; Corporate Secretary, Controller and Chief Accounting Officer, 1993 – 2001.
D. E. Gaines	47	Vice President Finance and Treasurer since March 2002; Vice President and Treasurer, 2001 – 2002; Treasurer, 1994 – 2001.
K. J. Harris	40	Vice President Regulatory and Government Affairs since February 2003; Vice President Regulatory Affairs, 2002 – 2003; Director Load Resource Strategies and Associate General Counsel, 2001 – 2002; Associate General Counsel, 1999 – 2001.
J. L. Henry	59	Senior Vice President Energy Efficiency and Customer Services since February 2003; Director of Major Accounts, 2001 – 2003; Director Construction and Technical Field Services 2000 – 2001.
E. M. Markell	53	Senior Vice President Energy Resources since February 2003; Vice President Corporate Development, 2002 – 2003. Prior to joining PSE, he was Chief Financial Officer, Club One, Inc., 2000 – 2002.
S. McLain	48	Senior Vice President Operations since February 2003; Vice President Operations – Delivery, 1999 – 2003.
J. L. O'Connor	48	Vice President and General Counsel since January 2003. Prior to joining PSE, she was interim General Counsel, Starbucks Corporation, 2002; Senior Vice President and Deputy General Counsel, Starbucks Corporation, 2001 – 2002; Vice President and Assistant General Counsel, Starbucks Corporation, 1998 – 2001.
J. M. Ryan	42	Vice President Risk Management and Strategic Planning since April 2004; Vice President Energy Portfolio Management, 2001 – 2004. Prior to joining PSE, she was Managing Director of North American Marketing of TransAlta USA, 2001; Managing Director Origination of Merchant Energy Group of the Americas, Inc., 1997 – 2001.

B. A. Valdman	41	Senior Vice President Finance and Chief Financial Officer since December 2003. Prior to joining PSE, he was Managing Director with JP Morgan Securities, Inc., 2000 – 2003 and a member of the Natural Resource Group of JP Morgan Securities, Inc. since 1993 and a banker with JP Morgan since 1987.
P. M. Wiegand	52	Vice President Project Development and Contract Management since July 2003; Vice President Corporate Planning, 2003; Vice President Corporate Planning and Performance, 2002 – 2003; Vice President Risk Management and Strategic Planning 2000 – 2002.

ITEM 2. PROPERTIES

The principal electric generating plants and underground gas storage facilities owned by PSE are described under Item 1, Business - Electric Supply and Gas Supply. PSE owns its transmission and distribution facilities and various other properties. Substantially all properties of PSE are subject to the liens of PSE's mortgage indentures. PSE's corporate headquarters is housed in a leased building located in Bellevue, Washington.

InfrastruX operates a fleet of vehicles and equipment that it uses in its utility construction business. Its fleet is composed of owned and leased trucks and other specialized equipment such as backhoes, trenchers, boring machines, cranes and other equipment required to perform its work. InfrastruX owns some of the facilities out of which it operates and rents the remaining facilities. The majority of InfrastruX's owned facilities are subject to liens under existing debt and lines of credit. InfrastruX's corporate headquarters is housed in a leased building located in Bellevue, Washington.

ITEM 3. LEGAL PROCEEDINGS

See the section under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations-Proceedings Relating to the Western Power Market.

Contingencies arising out of the normal course of the Company's business exist at December 31, 2004. The ultimate resolution of these issues are not expected to have a material adverse impact on the financial condition, results of operations or liquidity of the Company.

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

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Puget Energy's common stock, the only class of common equity of Puget Energy, is traded on the New York Stock Exchange under the symbol "PSD." At February 23, 2005, there were approximately 40,400 holders of record of Puget Energy's common stock. The outstanding shares of PSE's common stock, the only class of common equity of PSE, are held by Puget Energy and are not traded.

The following table shows the market price range of, and dividends paid on, Puget Energy's common stock during the periods indicated in 2004 and 2003. Puget Energy and its predecessor companies have paid dividends on common stock each year since 1943 when such stock first became publicly held.

	2004			2003		
	Price Range		Dividends	Price Range		Dividends
Quarter Ended	High	Low	Paid	High	Low	Paid
March 31	$23.92	$21.59	$0.25	$23.00	$18.10	$0.25
June 30	22.88	20.51	0.25	24.40	20.78	0.25
September 30	23.00	21.05	0.25	24.17	21.02	0.25
December 31	24.81	22.27	0.25	23.99	22.14	0.25

The amount and payment of future dividends will depend on Puget Energy's financial condition, results of operations, capital requirements and other factors deemed relevant by Puget Energy's Board of Directors. The Board of Directors' current policy is to pay out approximately 60% of normalized utility earnings in dividends.

Puget Energy's primary source of funds for the payment of dividends to its shareholders is dividends received from PSE. PSE's payment of common stock dividends to Puget Energy is restricted by provisions of certain covenants applicable to preferred stock and long-term debt contained in PSE's Articles of Incorporation and electric and gas mortgage indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $274.4 million at December 31, 2004.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected financial data. Puget Energy became the holding company for PSE on January 1, 2001 pursuant to a plan of exchange in which each share of PSE common stock was exchanged on a one-for-one basis for Puget Energy common stock. Puget Energy results are not on a comparable basis as InfrastruX had acquisitions from 2000 to 2003.

PUGET ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS, EXCEPT PER SHARE DATA)

YEARS ENDED DECEMBER 31	2004	2003[1]	2002	2001[2]	2000[3]
Operating revenue [4]	$ 2,568,813	$ 2,382,803	$ 2,315,181	$ 2,886,560	$ 3,302,296
Operating income	216,751	305,175	309,669	297,121	363,872
Net income before cumulative effect of accounting change	55,022	116,366	110,052	113,175	193,831
Net income from continuing operations[5]	55,022	116,197	110,052	98,426	184,837
Basic earnings per common share from continuing operations	0.55	1.23	1.24	1.14	2.16
Diluted earnings per common share from continuing operations	0.55	1.22	1.24	1.14	2.16
Dividends per common share	$ 1.00	$ 1.00	$ 1.21	$ 1.84	$ 1.84
Book value per common share	16.25	16.71	16.27	15.66	16.61
Total assets at year end	$ 5,833,369	$ 5,699,002	$ 5,772,133	$ 5,668,481	$ 5,677,266
Long-term obligations	2,212,532	1,969,489	2,160,276	2,127,054	2,170,797
Preferred stock subject to mandatory redemption	1,889	1,889	43,162	50,662	58,162
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	300,000	300,000	100,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250	--	--	--

1 *In 2003, FASB issued Interpretation No. 46 (FIN 46) which required the consolidation of PSE's 1995 Conservation Trust Transaction. As a result, revenues and expense increased $5.7 million with no effect on net income, and assets and liabilities increased $4.2 million in 2003. FIN 46 also required deconsolidation of PSE's trust preferred securities that are now classified as junior subordinated debt. This deconsolidation has no impact on assets, liabilities, receivables or earnings for 2003.*

2 *In 2001, SFAS No. 133 was implemented, which required derivative instruments to be valued at fair price.*

3 *Amounts represent PSE activity prior to the formation of Puget Energy as a holding company of PSE on January 1, 2001.*

4 *Operating Electric Revenues and Purchased Electricity expenses in 2003 and 2002 were revised as a result of implementing Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03" (EITF No. 03-11), which became effective on January 1, 2004. Operating Electric Revenues and Purchased Electricity expense for Puget Energy and Puget Sound Energy were reduced by $108.7 million and $77.1 million in 2003 and 2002, respectively, with no effect on net income. Information for 2001 and 2000 is not available, and therefore revenue and expense were not adjusted for the effects of EITF No. 03-11 in those years.*

5 *Net income in 2000 includes preferred stock dividend accrual at PSE, which is treated as an other deduction at Puget Energy starting January 1, 2001.*

PUGET SOUND ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS)

YEARS ENDED DECEMBER 31	2004	2003[1]	2002	2001[2]	2000
Operating revenue [3]	$ 2,198,877	$ 2,041,016	$ 1,995,652	$ 2,712,774	$ 3,302,296
Operating income	288,241	297,904	294,593	288,480	363,8872
Net income before cumulative effect of accounting change	126,192	120,055	108,948	119,130	193,831
Income for common stock from continuing operations	126,192	114,735	101,117	95,968	184,837
Total assets at year end	$ 5,564,087	$ 5,359,104	$ 5,453,390	$ 5,439,253	$ 5,677,266
Long-term obligations	2,064,360	1,950,347	2,021,832	2,053,815	2,170,797
Preferred stock subject to mandatory redemption	1,889	1,889	43,162	50,662	58,162
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	300,000	300,000	100,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250	--	--	--

1 *In 2003, FASB issued Interpretation No. 46 (FIN 46) which required the consolidation of PSE's 1995 Conservation Trust Transaction. As a result, revenues and expense increased $5.7 million with no effect on net income, and assets and liabilities increased $4.2 million in 2003. FIN 46 also required deconsolidation of PSE's trust preferred securities that are now classified as junior subordinated debt. This deconsolidation has no impact on assets, liabilities, receivables or earnings for 2003.*

2 *In 2001, SFAS No. 133 was implemented, which required derivative instruments to be valued at fair price.*

3 *Operating Electric Revenues and Purchased Electricity Expenses in 2003 and 2002 were revised as a result of implementing Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03" (EITF No. 03-11), which became effective on January 1, 2004. Operating Electric revenues and Purchased Electricity expense for Puget Energy and Puget Sound Energy were reduced by $108.7 million and $77.1 million in 2003 and 2002, respectively, with no effect on net income. Information for 2001 and 2000 is not available, and therefore revenue and expense were not adjusted for the effects of EITF No. 03-11 in those years.*

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the financial statements and related notes thereto included elsewhere in this annual report on Form 10-K. The discussion contains forward-looking statements that involve risks and uncertainties, such as Puget Energy's and Puget Sound Energy's (PSE) objectives, expectations and intentions. Words or phrases such as "anticipates," "believes," "estimates," "expects," " plans," "predicts," "projects," "will likely result," "will continue" and similar expressions are intended to identify certain of these forward-looking statements. However, these words are not the exclusive means of identifying such statements. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. Puget Energy's and PSE's actual results could differ materially from results that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed in the section entitled "Forward-Looking Statements" included elsewhere in this report. Except as required by law, neither Puget Energy nor PSE undertakes an obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. Readers are urged to carefully review and consider the various disclosures made in this report and in Puget Energy's and PSE's other reports filed with the United States Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect Puget Energy's and PSE's business, prospects and results of operations.

OVERVIEW

Puget Energy is an energy services holding company, and all its operations are conducted through its two subsidiaries. These subsidiaries are PSE, a regulated electric and gas utility company, and InfrastruX, a utility construction and services company. On February 8, 2005, following a strategic review of InfrastruX, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy intends to monetize its interest in InfrastruX through sale or recapitalization and to invest the proceeds of such monetization in its regulated utility subsidiary, PSE.

PUGET SOUND ENERGY

PSE generates revenues from the sale of electric and gas services, mainly to residential and commercial customers within Washington State. A majority of PSE's revenues are generated in the first and fourth quarters during the winter heating season in Washington State.

As a regulated utility company, PSE is subject to Federal Energy Regulatory Commission (FERC) and Washington Commission regulation which may impact a large array of business activities, including limitation of future rate increases; directed accounting requirements that may negatively impact earnings; licensing of PSE-owned generation facilities; and other FERC and Washington Commission directives that may impact PSE's long-term goals. In addition, PSE is subject to risks inherent to the utility industry as a whole, including weather changes affecting purchases and sales of energy; outages at owned and non-owned generation plants where energy is obtained; storms or other events which can damage electric distribution and transmission lines; and energy trading and wholesale market stability over time.

PSE's main operational goal has been to provide reliable, safe and cost-effective energy to its customers. To help accomplish this goal, PSE is attempting to be more self-sufficient in energy generation resources. Owning more generation resources rather than purchasing power through contracts and on the wholesale market is intended to allow customers' rates to remain stable. PSE is continually exploring new electric-power resource generation and long-term purchase power agreements to meet this goal. During 2004, PSE made progress in reaching this goal:

- Purchased a 49.85% interest in a 250 MW capacity gas-fired generation facility in western Washington, which went into service in April 2004.
- Signed a two-year purchase power agreement in the second quarter 2004 with another utility for 85 MW of energy with delivery beginning January 1, 2005.
- Signed a non-binding letter of intent in September 2004 to purchase a wind generation facility with up to 230 MW of generation to be developed in central Washington State.
- Signed a non-binding letter of intent in October 2004 to purchase a wind generation facility with up to 150 MW of generation to be developed in eastern Washington State.

These transactions and proposed transactions are part of PSE's long-term electric Least Cost Plan that was filed August 29, 2003 with the Washington Commission. The plan supports a strategy of diverse resource acquisitions including resources fueled by natural gas and coal, renewable resources and shared resources. PSE is in the process of updating its Least Cost Plan and expects to file the updated plan with the Washington Commission in the first half of 2005.

INFRASTRUX

Following a strategic review of InfrastruX conducted by Puget Energy management, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. During 2005, Puget Energy intends to monetize its interest in InfrastruX through a sale or third party recapitalization and to invest the proceeds in PSE. The costs associated with exiting the InfrastruX business cannot be quantified at this time. However, Puget Energy believes that such costs will not be material given the effects of the impairment charge recorded in the fourth quarter 2004.

InfrastruX generates revenues mainly from maintenance services and construction contracts in the Midwest, Texas, south-central and eastern United States. Generally, the majority of its revenues are generated during the second and third quarters, which are typically the most productive quarters for the construction industry due to longer daylight hours and generally better weather conditions.

InfrastruX is subject to risks associated with the construction industry, including inability to adequately estimate costs of projects that are bid on under fixed-fee contracts; continued economic downturn that limits the amount of projects available thereby reducing available profit margins due to increased competition; the ability to integrate acquired companies within its operations without significant cost; and the ability to obtain adequate financing and bonding coverage to continue expansion and growth.

InfrastruX's main goals have been continued growth and expansion into underdeveloped utility construction markets and to utilize its acquired entities to capitalize on depth of expertise, asset base, geographical location and workforce to provide services that local contractors cannot provide. InfrastruX has acquired 12 entities since 2000.

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiaries, PSE and InfrastruX. Net income in 2004 was $55.0 million on operating revenues of $2.6 billion compared to $116.2 million on operating revenues of $2.4 billion in 2003 and $110.1 million on operating revenues of $2.3 billion in 2002.

Basic earnings per share in 2004 were $0.55 on 99.5 million weighted average common shares outstanding compared to $1.23 on 94.8 million weighted average common shares outstanding in 2003 and $1.24 on 88.4 million weighted average common shares outstanding in 2002. Diluted earnings per share in 2004 were $0.55 on 99.9 million weighted average common shares outstanding compared to $1.22 on 95.3 million weighted average common shares outstanding in 2003 and $1.24 on 88.8 million weighted average common shares outstanding in 2002.

Net income in 2004 was adversely impacted by an InfrastruX non-cash goodwill impairment charge of $91.2 million ($76.6 million after tax and minority interest) and a $43.4 million ($28.2 million after-tax) disallowance of the return on the Tenaska gas supply regulatory asset as a result of a Washington Commission order in PSE's Power Cost Only Rate Case (PCORC). Net income was also negatively impacted by an increase in depreciation expense of $10.0 million, primarily due to the acquisition of Frederickson 1 and other PSE infrastructure projects. These negative impacts were offset by improved electric margins of $5.9 million compared to 2003 and lower interest expense at PSE of $13.0 million. In addition, 2004 was not impacted by one-time tax benefits of $7.9 million or the write-down of $6.1 million in the carrying value of a non-utility venture capital investment in 2003. Net income in 2004 was positively impacted by a $4.3

million increase in InfrastruX's net income, excluding the goodwill impairment charge and net of minority interest. The net income increase at InfrastruX was due to improved operating efficiencies and improvements in weather conditions compared to 2003, which positively impacted productivity.

Net income in 2003 was positively impacted by an increase in PSE's net income of $10.9 million due to increased electric and gas margins primarily from a general gas rate increase effective September 1, 2002 and from increased sales volumes for electric and gas loads compared to 2002. In addition, net income in 2003 was positively impacted by lower interest expenses of $11.5 million. This was offset by a $6.1 million downward adjustment in the carrying value of a non-utility venture capital investment in the fourth quarter 2003; a $4.8 million increase in depreciation and amortization; and an $11.7 million decrease in gains on derivative instruments due to a 2002 gain from de-designated contracts from a non-creditworthy counterparty under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In addition, federal tax benefits decreased in 2003 to $9.3 million compared to $10.3 million in 2002. Net income was also negatively impacted by a decrease in InfrastruX's net income of $7.7 million in 2003 compared to 2002, net of minority interest, due to unusually wet weather affecting productivity in the first quarter 2003 and increased competition in the marketplace.

PUGET SOUND ENERGY

PSE's 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. PSE normally experiences its highest retail energy sales during the heating season in the first and fourth quarters of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult.

PUGET SOUND ENERGY
2004 COMPARED TO 2003

ENERGY MARGINS

The following table displays the details of electric margin changes from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	ELECTRIC MARGIN 2004	2003	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 1,310.9	$ 1,272.7	$ 38.2	3.0%
Electric transportation revenue	10.7	11.5	(0.8)	(7.0)
Other electric revenue-gas supply resale	11.5	9.1	2.4	26.4
Total electric revenue for margin	1,333.1	1,293.3	39.8	3.1
Adjustments for amounts included in revenue:				
Pass-through tariff items	(25.4)	(45.2)	19.8	43.8
Pass-through revenue-sensitive taxes	(94.2)	(91.0)	(3.2)	(3.5)
Residential exchange credit	174.5	173.8	0.7	0.4
Net electric revenue for margin	1,388.0	1,330.9	57.1	4.3
Minus power costs:				
Fuel	(80.7)	(65.0)	(15.7)	(24.2)
Purchased electricity, net of sales to other utilities and marketers	(660.3)	(635.2)	(25.1)	(4.0)
Total electric power costs	(741.0)	(700.2)	(40.8)	(5.8)
Electric margin before PCA	647.0	630.7	16.3	2.6
Tenaska disallowance reserve through May 23, 2004	(36.5)	--	(36.5)	*
Tenaska reserve turnaround	10.5	--	10.5	*
Power cost deferred under the PCA mechanism	19.1	3.5	15.6	*
Electric margin	$ 640.1	$ 634.2	$ 5.9	0.9%

* *Percent change not applicable.*

Electric margin increased $5.9 million in 2004 compared to 2003 due primarily to an increase in kWh sales and the PCORC rate increase. PSE incurred $34.8 million in excess power costs in 2003 before reaching the $40 million PCA mechanism cap in 2003. In addition, the PCORC rate increase of 3.2% related to the Frederickson 1 generating facility became effective on May 24, 2004. This rate increase provided an additional $6.5 million to electric margin in 2004 to recover utility operation and maintenance costs, depreciation and property taxes related to the Frederickson 1 generating facility. Also, retail customer kWh sales (residential, commercial and industrial customers) increased 1.5% in 2004 compared to 2003, which along with a change in customer class usage provided an additional $11.7 million to electric margin. These increases were partially offset by the disallowance of certain gas costs for the Tenaska generating facility also ordered in the PCORC, which resulted in a $43.4 million reduction of electric margin in 2004. In addition, a charge of $3.6 million associated with Colstrip Units 1 & 2 coal supply repricing arbitration and Colstrip Units 3 & 4 royalty charge resulted in a negative impact to electric margin. Electric margin is electric sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of generating and purchasing electric energy sold to customers including transmission costs to bring electric energy to PSE's service territory.

The following table displays the details of gas margin changes from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2004	2003	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 743.6	$ 609.6	$ 134.0	22.0%
Gas transportation revenue	13.0	13.8	(0.8)	(5.8)
Total gas revenue for margin	756.6	623.4	133.2	21.4
Adjustments for amounts included in revenue:				
Gas revenue hedge	--	0.2	(0.2)	*
Pass-through tariff items	(3.6)	(3.8)	0.2	5.3
Pass-through revenue-sensitive taxes	(59.3)	(48.5)	(10.8)	(22.3)
Net gas revenue for margin	693.7	571.3	122.4	21.4
Minus purchased gas costs	(451.3)	(327.1)	(124.2)	(38.0)
Gas margin	$ 242.4	$ 244.2	$ (1.8)	(0.7)%

* *Percent change not applicable.*

Gas margin decreased $1.8 million in 2004 compared to 2003 primarily due to overall warmer weather in 2004 compared to 2003, partially offset by customer additions in 2004. Heating degree days decreased 2.3% in 2004 compared to 2003, which resulted in a 1.5% reduction in therm sales. Gas margin is gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes and the cost of gas purchased, including gas transportation costs to bring gas to PSE's service territory.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2004	2003	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 628.9	$ 603.7	$ 25.2	4.2%
Commercial sales	581.0	556.0	25.0	4.5
Industrial sales	88.8	88.2	0.6	0.7
Transportation sales	10.7	11.5	(0.8)	(7.0)
Sales to other utilities and marketers	56.5	82.8	(26.3)	(31.8)
Other	57.1	58.5	(1.4)	(2.4)
Total electric operating revenues	$ 1,423.0	$ 1,400.7	$ 22.3	1.6%

Electric operating revenues increased $22.3 million in 2004 compared to 2003 due to increases in residential and commercial customer usage and the effect of the PCORC rate increase. Residential and commercial electricity usage increased 182,296 MWh or 1.9% and 227,400 MWh or 2.8%, respectively, from 2003. The increase in electricity usage was mainly the result of a higher average number of customers served in 2004 compared to 2003. Average customers for the residential and commercial customer classes increased 2.4% and 1.1%, respectively, from 2003. In addition, the PCORC rate increase became effective on May 24, 2004 and provided a $24.5 million increase in electric operating revenue, net of a $5.8 million rate reduction due to the Tenaska disallowance.

Sales to other utilities and marketers decreased $26.3 million from 2003 primarily due to higher retail electric sales, which reduced excess generation for sale to the wholesale market. In 2003, warmer than normal temperatures, mainly in the first quarter, and improved hydroelectric conditions as compared to the original hydroelectric forecast provided excess energy supplies for sale to the wholesale market.

During 2004, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $182.6 million compared to $181.9 million in 2003. This credit also reduces power costs by a corresponding amount with no impact on earnings. See Item 1, Business – Regulation and Rates – Residential and Small Farm Exchange Benefit Credit for further discussion.

During 2003, PSE collected in its electric general rate tariff as a reduction to revenue and remitted to a grantor trust $7.7 million. This was a result of PSE's 1995 sale of future electric revenues associated with its investment in conservation assets. The impact of the 1995 sale of revenue was offset by reductions in conservation amortization and interest expense. PSE's 1995 conservation trust transaction was consolidated in the third quarter 2003 to meet the guidance of Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46) and, as a result, revenues increased $5.7 million in 2004 while conservation amortization and interest expense increased by a corresponding amount with no impact on earnings. The 1995 conservation trust assets were fully satisfied during September 2004.

GAS OPERATING REVENUES

The table below sets forth changes in gas operating revenues for PSE from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2004	2003	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 479.0	$ 401.7	$ 77.3	19.2%
Commercial sales	225.8	178.2	47.6	26.7
Industrial sales	38.8	29.7	9.1	30.6
Transportation sales	13.0	13.8	(0.8)	(5.8)
Other	12.7	10.8	1.9	17.6
Total gas operating revenues	$ 769.3	$ 634.2	$ 135.1	21.3%

Gas operating revenues increased $135.1 million or 21.3% in 2004 compared to 2003 due primarily to higher Purchased Gas Adjustment (PGA) mechanism rates in 2004. The PGA mechanism rate charged to customers has increased twice since April 2003 reflecting the higher cost of natural gas provided to customers. On September 24, 2003, the Washington Commission approved a PGA mechanism rate increase of 13.3% annually across all classes of customers effective October 1, 2003. In addition, the Washington Commission approved a third PGA mechanism rate increase effective October 1, 2004 that increased rates 17.6% annually. The PGA mechanism passes through to customers increases or decreases in the gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in gas pipeline transportation costs. PSE's gas margin and net income are not affected by changes under the PGA mechanism. For 2004, the effects of the PGA mechanism rate increases provided an increase of $137.0 million in gas operating revenues. These rate increases were partially offset with lower therm sales due to 2.3% fewer heating degree days in 2004 compared to 2003.

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2004	2003	CHANGE	PERCENT CHANGE
Purchased electricity	$ 723.6	$ 714.5	$ 9.1	1.3 %
Electric generation fuel	80.8	65.0	15.8	24.3
Purchased gas	451.3	327.1	124.2	38.0
Utility operations and maintenance	291.2	289.7	1.5	0.5
Depreciation and amortization	228.6	220.1	8.5	3.9
Conservation amortization	22.7	33.5	(10.8)	(32.2)
Taxes other than income taxes	209.0	194.9	14.1	7.2
Income taxes	77.1	70.9	6.2	8.7

Purchased electricity expenses increased $9.1 million in 2004 compared to 2003 as a result of a $36.5 million disallowance associated with the Tenaska generating facility as ordered by the Washington Commission in the PCORC. This decrease was partially offset by lower purchases of electricity due to increased generation at PSE generating facilities. Total generation at PSE generating facilities in 2004 increased 82,430 MWh or 1.2% in 2004 compared to 2003.

PSE's hydroelectric production and related power costs in 2004 and 2003 have continued to be negatively impacted by below-normal winter precipitation and reduced snow pack in the Pacific Northwest region. The January 3, 2005 Columbia Basin Runoff Summary published by the National Weather Service Northwest River Forecast Center indicated that the total observed runoff above Grand Coulee Reservoir for the period January through December 2004 was 88% of normal, which compares to 87% of normal for the same period in 2003. PSE cannot determine if this trend of lower than normal runoff will continue in future years nor what impact such a trend may have on the amount of electricity that will need to be purchased. PSE had previously reached the $40 million cumulative cap under the PCA mechanism in 2003 primarily due to increased power costs and adverse hydroelectric conditions. In 2004, PSE fell below the $40 million cumulative cap due to the Tenaska disallowance. Under the PCA mechanism, continued excess power costs and further increases in variable power costs through June 30, 2006 will be apportioned 99% to customers and 1% to PSE. PSE has reserved the Tenaska disallowance and as a result any future excess power costs will be offset by the reserve. For further discussion see Item 1 – Business – Regulation and Rates – Electric Regulation and Rates – Washington Commission Matters.

To meet customer demand, PSE economically dispatches resources in its power supply portfolio such as fossil-fuel generation, owned and contracted hydroelectric capacity and energy, and long-term contracted power. However, depending principally upon availability of hydroelectric energy, plant availability, fuel prices and/or changing load as a result of weather, PSE may sell surplus power or purchase deficit power in the wholesale market. PSE manages its core energy portfolio through short-term and intermediate-term off-system physical purchases and sales, and through other risk management techniques.

Electric generation fuel expense increased $15.8 million in 2004 compared to 2003 as a result of higher fuel costs for PSE-controlled gas-fired generation facilities and the addition of the Frederickson 1 generating facility, which was purchased and went into service in April 2004. In addition, the 12 months ended December 31, 2004 includes a $6.9 million charge related to a binding arbitration settlement between PSE and Western Energy Company (WECO), the supplier of coal to Colstrip Units 1 & 2. The binding decision retroactively set a new baseline cost per ton of coal supplied from July 31, 2001, and is applicable to the remaining term of the coal supply agreement through December 2009. Of the $6.9 million charge, $5.0 million is included in the PCA mechanism. PSE had previously accrued a reserve of $1.6 million in the fourth quarter 2003 related to the arbitration.

The 12 months ended December 31, 2004 also includes a loss reserve of $1.1 million recorded in the second quarter 2004 related to an order issued to WECO by the Minerals Management Services of the United States Department of the Interior (MMS) on April 29, 2004, to pay additional royalties concerning coal purchased by PSE for Colstrip Units 3 & 4. The order seeks payment of royalties for coal mined from federal land between 1997 and June 30, 2000. During that period, PSE's coal price was reduced by a settlement agreement entered into in February 1997 among PSE, WECO and Montana Power Company that resolved disputes that were then pending. The order seeks to impute the price charged to PSE based on the other Colstrip Units 3 & 4 owners' contractual amounts. PSE is supporting WECO's appeal of the order, but is also evaluating the basis of the claim.

In addition, the MMS issued two orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 & 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 & 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. PSE's share of the alleged additional royalties is $1.8 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. Other parties may attempt to assert claims against WECO if the MMS position prevails. The transportation agreement provides for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip Units 3 & 4. WECO has appealed these orders and PSE is monitoring the process. Based upon its review, PSE believes that the Colstrip Units 3 & 4 owners have reasonable defenses in this matter. Neither the outcome of this matter nor the associated costs can be predicted at this time.

Purchased gas expenses increased $124.2 million in 2004 compared to 2003 primarily due to an increase in PGA rates as approved by the Washington Commission. The PGA mechanism allows PSE to recover expected gas costs, and defer, as a receivable or liability, any gas costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism had a receivable balance at December 31, 2004 of $19.1 million compared to a liability balance of $12.0 million at December 31, 2003. A receivable balance in the PGA mechanism reflects a current underrecovery of market gas cost through rates and a liability balance reflects a current overrecovery of gas cost. For further discussion on PGA rates see Item 1 – Business - Gas Regulation and Rates.

Utility operations and maintenance expense increased $1.5 million in 2004 compared to 2003 which includes a decrease of $1.8 million related to low-income program costs that are passed-through in retail rates with no impact on earnings. As a result, the pre-tax impact on net income from utility operations and maintenance was an increase of $3.3 million due primarily to a $3.2 million increase in storm damage costs primarily from a severe ice storm that hit the Pacific Northwest in January 2004. PSE anticipates operation and maintenance expense to increase in future years as PSE invests in new generating resources and energy delivery infrastructure.

Depreciation and amortization expense increased $8.5 million in 2004 compared to 2003 due primarily to the effects of new plant placed in service during 2004, including $80.8 million in costs for the Frederickson 1 generating facility and $32.8 million for the Everett Delta gas transmission line. PSE anticipates depreciation expense will increase in future years as PSE invests in new generating resources and energy delivery infrastructure.

Conservation amortization decreased $10.8 million in 2004 compared to 2003 due to the conservation trust assets being fully amortized in September 2004. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased $14.1 million in 2004 compared to 2003 primarily due to increases in revenue-based Washington State excise tax and municipal tax due to increased operating revenues. Revenue sensitive excise and municipal taxes have no impact on earnings.

Income taxes increased $6.2 million in 2004 compared to 2003 as a result of the non-recurrence in 2004 of $9.3 million in income tax benefits in 2003 offset by a one-time income tax benefit of $1.4 million in 2004 related to a 2001 tax audit.

OTHER INCOME, INTEREST CHARGES AND PREFERRED STOCK DIVIDENDS

The table below sets forth significant changes in other income, interest charges and preferred stock dividends for PSE and its subsidiaries from 2003 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2004	2003	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 4.4	$ 1.6	$ 2.8	175.0 %
Interest charges	166.4	179.4	(13.0)	(7.2)
Preferred stock dividends	--	5.2	(5.2)	(100.0)

Other income increased $2.8 million (after-tax) due to the non-recurrence of a $4.0 million investment write-down in 2003 related to a non-utility venture capital investment and a $0.9 million collection in 2004 of a note previously written-off in 2002. These increases were partially offset with the non-recurrence of a $1.9 million gain from a security sale in 2003 and the non-recurrence of gains on corporate life insurance of $1.7 million in 2003.

Interest charges decreased $13.0 million in 2004 due to the redemption of $157.7 million of long-term debt with rates ranging from 6.07% to 7.80% in 2004, partially offset with the issuance of $200 million of variable-rate senior notes in July 2004.

Preferred stock dividends decreased $5.2 million in 2004 due to the redemption on November 1, 2003 of the 7.45% series preferred stock not subject to mandatory redemption. The series was redeemed at par value plus accrued dividends.

INFRASTRUX
2004 COMPARED TO 2003

The table below sets forth significant changes in revenues and expenses for InfrastruX from 2003 to 2004.

(DOLLARS IN MILLIONS) YEARS ENDED DECEMBER 31	2004	2003	CHANGE	PERCENT CHANGE
Operating revenue:				
Non-utility construction services	$ 369.9	$ 341.8	$ 28.1	8.2 %
Other operations and maintenance	$ 320.2	$ 302.4	$ 17.8	5.9%
Depreciation and amortization	18.3	16.8	1.5	8.9
Goodwill impairment	91.2	--	91.2	*
Income taxes	(1.8)	1.6	(3.4)	(212.5)
Interest charges	$ 6.5	$ 5.5	$ 1.0	18.2%
Minority interest	7.1	(0.2)	7.3	*

* *Percent change not applicable.*

InfrastruX revenues increased $28.1 million due in part to the acquisition of one company late in the second quarter 2003 which added $12.4 million to revenues. Revenues from existing companies increased $8.7 million in 2004 compared to 2003 due to strong performance in the electric transmission sector of the construction services industry and new business in the Midwest region of the United States.

Other operations and maintenance expenses increased $17.8 million due to increased utility construction in 2004 compared to 2003 and the acquisition of one company late in the second quarter 2003, which accounted for $11.8 million of the increase.

Depreciation and amortization expense increased $1.5 million in 2004 compared to 2003 primarily due to an increase in assets through a company acquisition late in the second quarter 2003 which accounted for $0.8 million of the increase and implementation of an integrated information technology platform across InfrastruX.

Goodwill impairment. In the fourth quarter 2004, as part of the required annual goodwill impairment review as required by Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangible Assets,” InfrastruX recorded a non-cash, pre-tax goodwill impairment charge of $91.2 million. This charge reflected Puget Energy’s estimated fair value for InfrastruX in light of ongoing challenges in the utility construction services sector.

Income taxes decreased $3.4 million in 2004 compared to 2003. Included in the change was a $25.0 million deferred income tax benefit associated with the goodwill impairment charge, offset by a $18.0 million valuation allowance against the deferred tax benefit as Puget Energy does not expect to utilize the full benefit. The remaining change in income tax was primarily the result of higher taxable income at InfrastruX in 2004 compared to 2003.

Interest charges increased $1.0 million in 2004 compared to 2003 primarily due to a higher average debt balance in 2004 than in 2003 and higher interest rates.

Minority interest increased $7.3 million in 2004 compared to 2003 as a result of the change in net loss associated with the goodwill impairment charge in 2004.

PUGET SOUND ENERGY
2003 COMPARED TO 2002

ENERGY MARGINS

The following table displays the details of electric margin changes from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	ELECTRIC MARGIN 2003	2002	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 1,272.7	$ 1,260.9	$ 11.8	0.9 %
Electric transportation revenue	11.5	15.6	(4.1)	(26.3)
Other electric revenue-gas supply resale	9.1	(20.4)	29.5	144.6
Total electric revenue for margin	1,293.3	1,256.1	37.2	3.0
Adjustments for amounts included in revenue:				
Pass-through tariff items	(45.2)	(32.1)	(13.1)	(40.8)
Pass-through revenue-sensitive taxes	(91.0)	(88.5)	(2.5)	(2.8)
Residential exchange credit	173.8	150.0	23.8	15.9
Net electric revenue for margin	1,330.9	1,285.5	45.4	3.5
Minus power costs:				
Fuel	(65.0)	(113.5)	48.5	42.7
Purchased electricity, net of sales to other utilities and marketers	(635.2)	(557.1)	(78.1)	(14.0)
Total electric power costs	(700.2)	(670.6)	(29.6)	(4.4)
Electric margin before PCA	630.7	614.9	15.8	2.6
Power cost deferred under the PCA mechanism	3.5	--	3.5	*
Electric margin	$ 634.2	$ 614.9	$ 19.3	3.1 %

* *Percent change not applicable.*

Electric margin increased $19.3 million for 2003 compared to 2002 due primarily to the non-recurrence of losses associated with the resale of gas supply for electric generation in 2002 and increased MWh sales of 1.5%. Electric margin is electric sales to retail and transportation customers less pass-through tariff items and revenue sensitive taxes, and the cost of generating and purchasing electric energy sold to customers including transmission costs to bring electric energy to PSE's service territory.

The following table displays the details of gas margin changes from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2003	2002	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 609.6	$ 673.2	$ (63.6)	(9.4)%
Gas transportation revenue	13.8	12.9	0.9	7.0
Total gas revenue for margin	623.4	686.1	(62.7)	(9.1)
Adjustments for amounts included in revenue:				
Gas revenue hedge	0.2	0.6	(0.4)	(66.7)
Pass-through tariff items	(3.8)	(2.3)	(1.5)	(65.2)
Pass-through revenue-sensitive taxes	(48.5)	(54.3)	5.8	10.7
Net gas revenue for margin	571.3	630.1	(58.8)	(9.3)
Minus purchased gas costs	(327.1)	(405.0)	77.9	19.2
Gas margin	$ 244.2	$ 225.1	$ 19.1	8.5 %

Gas margin increased $19.1 million in 2003 compared to 2002 due to the effects of the gas general rate increase effective September 1, 2002 that resulted in a $24.2 million increase in revenues in 2003. The increase was offset by a 2.1% decline in therm sales in 2003. Gas margin is gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes and the cost of gas purchased, including gas transportation costs to bring gas to PSE's service territory.

ELECTRIC OPERATING REVENUES

The table below sets forth significant changes in electric operating revenues for PSE from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2003	2002	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 603.7	$ 616.5	$ (12.8)	(2.0)%
Commercial sales	556.0	536.0	20.0	3.7
Industrial sales	88.2	90.1	(1.9)	(2.1)
Transportation sales	11.5	15.6	(4.1)	(26.2)
Sales to other utilities and marketers	82.8	11.1	71.7	*
Other	58.5	19.4	39.1	201.5
Total electric operating revenues	$1,400.7	$1,288.7	$ 112.0	8.7%

* *Percent change not applicable.*

Electric operating revenues increased $112.0 million in 2003 compared to 2002 due primarily to an increase of $71.7 million in wholesale electric sales to other utilities and marketers from greater surplus volumes. Wholesale sales volumes increased by 640,176 MWh or 94.5% compared to 2002. Retail sales volumes increased 337,154 MWh or 1.8% as a result of increased usage by commercial customers in 2003 compared to 2002. Electric operating revenues also increased by $27.4 million due primarily to the non-occurrence of 2002 losses on the sale of excess gas supply used for electric generation.

During 2003, the benefits of the Residential and Farm Energy Exchange Credit to customers reduced revenues by $181.9 million compared to $156.8 million in 2002. This credit also reduced power costs by a corresponding amount with no impact on earnings.

During 2003, PSE collected in its electric general rate tariff as a reduction to revenue and remitted to a grantor trust $7.7 million compared to $12.7 million for 2002 as a result of PSE's 1995 sale of future electric revenues associated with its investment in conservation assets. The impact of the sale of revenue was offset by reductions in conservation amortization and interest expense. PSE's 1995 conservation trust transaction was consolidated in the third quarter 2003 to meet the guidance of FIN 46 and, as a result, revenues increased $5.7 million while conservation amortization and interest expense increased by a corresponding amount with no impact on earnings. This amount was also forwarded to the grantor trust and any cash balance at the grantor trust was reported as restricted cash on the balance sheet.

GAS OPERATING REVENUES

The table below sets forth significant changes in gas operating revenues for PSE from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2003	2002	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 401.7	$ 428.6	$ (26.9)	(6.3)%
Commercial sales	178.2	209.5	(31.3)	(14.9)
Industrial sales	29.7	35.1	(5.4)	(15.4)
Transportation sales	13.8	12.9	0.9	7.0
Other	10.8	11.1	(0.3)	(2.7)
Total gas operating revenues	$ 634.2	$ 697.2	$ (63.0)	(9.0)%

Regulated gas utility revenues in 2003 compared to 2002 decreased by $63.0 million or 9.0% due primarily to lower PGA mechanism rates in 2003 as a result of refunding the previous overcollection of PGA mechanism gas costs. In addition, warmer temperatures in 2003 resulted in 8.5% fewer heating degree days as compared to 2002 resulting in lower therm sales.

PGA mechanism rates charged to customers were lower in 2003 compared to 2002 as a result of rate decreases of 7.3% and 12.5% which took effect September 1, 2002 and November 1, 2002, respectively, offset by a rate increase of 20.1% which took effect April 10, 2003, and another rate increase of 13.3% effective October 1, 2003.

OTHER OPERATING REVENUES

Other operating revenues decreased $3.8 million in 2003 compared to 2002 primarily due to a decrease in property sales gains for Puget Western, Inc., a PSE subsidiary, which generates a majority of its revenue through the development and sale of property.

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2003	2002	CHANGE	PERCENT CHANGE
Purchased electricity	$ 714.5	$ 568.2	$ 146.3	25.7 %
Electric generation fuel	65.0	113.5	(48.5)	(42.7)
Residential exchange power cost credit	(173.8)	(149.9)	(23.9)	(15.9)
Purchased gas	327.1	405.0	(77.9)	(19.2)
Unrealized (gain) loss on derivative instruments	0.1	(11.6)	11.7	100.8
Utility operations and maintenance	289.7	286.2	3.5	1.2
Depreciation and amortization	220.1	215.3	4.8	2.2
Conservation amortization	33.4	17.5	15.9	90.9
Taxes other than income taxes	194.9	202.4	(7.5)	(3.7)
Income taxes	70.9	52.8	18.1	34.2

Purchased electricity expenses increased $146.3 million in 2003 compared to 2002. PSE's hydroelectric production and related power costs in 2003 were negatively impacted by below-normal winter precipitation and snow pack in the Pacific Northwest region associated with an El Nino weather condition. The January 25, 2004 Columbia Basin Runoff Summary published by the National Weather Service Northwest River Forecast Center indicated that the total observed runoff above Grand Coulee Reservoir for the period January through December 2003 was 87% of normal. This compared to 108% of normal for the same period in 2002.

Electric generation fuel expense decreased $48.5 million in 2003 compared to 2002 as a result of lower fuel costs for PSE-controlled gas-fired generation facilities and the result of not operating the generating facilities due to available lower-cost wholesale power supply.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with Bonneville Power Administration (BPA) increased $23.9 million in 2003 compared to 2002 due to the impact of a full year's increased Residential and Farm Energy Exchange credit rate. The rate increased in January, March and October of 2002 for residential and small farm customers. Discussion of the amended Residential Purchase and Sale Agreement between PSE and BPA can be found under Item 1 – Business – Regulation and Rates – Residential and Small Farm Exchange Benefit Credit. The residential exchange credits are passed through to eligible residential and small farm customers by a corresponding reduction in revenues.

Purchased gas expenses decreased $77.9 million in 2003 compared to 2002 primarily due to a 2.1% decrease in sales volume, which was partially offset by an increase in PGA rates. The PGA mechanism allows PSE to recover expected gas costs. PSE defers, as a receivable or liability, any gas costs that exceed or fall short of the amount in PGA mechanism rates and accrues interest under the PGA mechanism. The PGA liability balance at December 31, 2003 was $12.0 million compared to a liability balance of $83.8 million at December 31, 2002.

Unrealized losses on derivative instruments increased $11.7 million in 2003 compared to 2002 as a result of unrealized losses on gas hedge contracts that were de-designated in the fourth quarter of 2001 and settled in 2002. The unrealized gains and losses recorded in the income statement are the result of the change in the market value of derivative instruments not meeting cash flow hedge criteria.

Utility operations and maintenance expense increased $3.5 million in 2003 compared to 2002, which included an increase of $3.3 million related to a full year of low-income program costs that were passed-through in retail rates with no impact on earnings. As a result, the pre-tax impact on net income from utility operations and maintenance expense was an increase of $0.2 million due primarily to an increase in electric overhead and underground line costs, gas distribution main costs, least cost planning costs, due diligence costs for power resource acquisition, certain costs associated with preparing the PCORC and meter reading expenses. The overall increase in utility operations and maintenance expenses was partially offset by a $2.0 million reduction of production operations and maintenance costs in 2003 compared to 2002 due to decreased operating costs of PSE's combustion turbine plants which were operated at lower levels in 2003 than in 2002 due to lower wholesale power prices. In addition, PSE's Personal Energy Management™ energy-efficiency program costs decreased $6.3 million in 2003 compared to 2002 reflecting a decreased emphasis on the program in light of relatively moderate energy prices and cancellation of the Time of Use program in November 2002. Also included in the results was pension income related to PSE's defined benefit pension plan which is allocated between capital and operations and maintenance expense based on the distribution of labor costs in accordance with FERC guidelines. As a result, approximately 67.0% of the annual qualified pension income of $12.9 million for 2003 was recorded as a reduction in operations and maintenance expense compared to 66.8% or $17.7 million for 2002. During the fourth quarter 2003, the Pacific Northwest region was hit by a severe windstorm that caused significant damage to PSE's electric distribution system. The windstorm was considered a "catastrophic event" under Washington Commission guidelines and as a result, PSE was able to defer the repair cost of $10.1 million for later recovery in retail rates.

Depreciation and amortization expense increased $4.8 million in 2003 compared to 2002 due primarily to the effects of a new plant placed in service during the past year.

Conservation amortization increased $15.9 million in 2003 compared to 2002 due to increased conservation expenditures and the result of consolidating the off-balance sheet conservation trust beginning July 1, 2003 in accordance with FIN 46. The consolidation of the conservation trust increased conservation amortization by $5.7 million for the period July through December 2003. Pass-through conservation costs are recovered through an electric conservation rider, a gas conservation tracker mechanism and a conservation trust rate schedule with no impact to earnings.

Taxes other than income taxes decreased $7.5 million in 2003 compared to 2002 primarily due to the 2002 property tax expense of $5.2 million related to the State of Oregon property tax bills covering a six-year period ending June 30, 2001 not recurring in 2003, a $1.4 million reduction in expense in the second quarter 2003 related to the settlement of the State of Oregon property tax bills and a $2.8 million decrease in revenue-based Washington State excise tax and municipal tax. This was offset by a $1.6 million increase in Washington State property taxes.

Income taxes increased $18.1 million in 2003 compared to 2002 as a result of increased income offset by true-ups related to filing the prior year's income tax returns, which reduced income tax expense by $3.0 million and a $6.2 million reduction in tax expense related to the favorable resolution of a federal income tax matter from 1997 to 2002 in the second quarter 2003. The increase was also the result of 2002 tax benefits totaling $10.3 million. The $10.3 million was composed of a $4.1 million refund related to the audit of the Company's 1998 and 1999 federal income tax returns, a $3.5 million reduction to income tax expense representing an adjustment to 2001 federal income tax based on the 2001 federal tax return and a $2.7 million reduction in expense related to a refund of federal income taxes for 2000.

OTHER INCOME, INTEREST CHARGES AND PREFERRED STOCK DIVIDENDS

The table below sets forth changes in other income, interest charges and preferred stock dividends for PSE and its subsidiaries from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2003	2002	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 1.6	$ 5.2	$ (3.6)	(69.2)%
Interest charges	179.4	190.9	(11.5)	(6.0)
Preferred stock dividends	5.2	7.8	(2.6)	(33.3)

Other income, net of federal income tax, decreased $3.6 million compared to 2002 reflecting a $4.0 million after-tax downward adjustment of the carrying value of a non-utility venture capital investment in the fourth quarter 2003.

Interest charges decreased $11.5 million for 2003 compared to 2002 primarily due to a decrease in long-term and short-term debt outstanding of $12.0 million and the maturity of $72.0 million of Medium-Term Notes with interest rates ranging from 6.20% to 7.02% during 2003, the early redemption of $123.0 million of Medium-Term Notes with interest rates ranging from 7.19% to 8.59% during 2003, and the refinancing of $161.9 million of Pollution Control Bonds with interest rates ranging from 5.875% to 7.25% to rates ranging from 5.00% to 5.10%. The decrease in interest expense was partially offset by the issuance of $150 million of senior notes, with an interest rate of 3.36%, in May 2003. PSE was able to pay maturing notes and redeem other notes mainly with additional equity investments by Puget Energy in 2003 and 2002.

Preferred stock dividends decreased $2.6 million in 2003 compared to 2002 due to the redemption of the 7.45% series preferred stock not subject to mandatory redemption for both sinking fund requirements and total redemption of the remaining shares in the series at par value plus accrued dividends in 2003.

INFRASTRUX
2003 COMPARED TO 2002

The table below sets forth significant changes in revenues and expenses for InfrastruX from 2002 to 2003.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2003	2002	CHANGE	PERCENT CHANGE
Non-utility construction services revenue	$ 341.8	$ 319.5	$ 22.3	7.0%
Other operations and maintenance	$ 302.4	$ 270.7	$ 31.7	11.7%
Depreciation and amortization	16.8	13.5	3.3	24.4
Income taxes	1.6	6.7	(5.1)	(76.1)

Non-utility construction services revenue increased $22.3 million in 2003 due primarily to acquisitions of several companies during 2002 and 2003, which contributed to an increase of $44.4 million. Excluding the impact of acquisitions, InfrastruX revenue decreased $22.1 million from 2002 due primarily to general market weakness and changing activities on certain lines of business. InfrastruX records revenues as services are performed or on a percent of completion basis for fixed-price projects.

Other operations and maintenance expenses increased $31.7 million in 2003 compared to 2002 due primarily to acquisitions of several companies during 2002 and 2003, which contributed to an increase of $37.1 million. Excluding the impact of acquisitions, operations and maintenance expenses decreased $5.4 million from 2002 due to lower productivity. The decrease, excluding the impact of acquisitions, was not proportionate to the decline in revenues due to the impact of severe wet weather on productivity during the first quarter 2003 as well as the high costs of completing work in low-volume activities in 2003.

Depreciation and amortization expense increased by $3.3 million in 2003 compared to 2002 due to acquisitions during 2003 and 2002, which were not owned during the full year of 2002.

Income taxes decreased $5.1 million in 2003 compared to 2002 due to lower income.

CAPITAL RESOURCES AND LIQUIDITY

CAPITAL REQUIREMENTS
CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Puget Energy. The following are Puget Energy’s aggregate consolidated (including PSE) contractual and commercial commitments as of December 31, 2004:

Puget Energy		Payments Due Per Period			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2005	2006-2007	2008-2009	2010 & Thereafter
Long-term debt	$ 2,251.4	$ 38.9	$ 552.0	$ 339.5	$ 1,321.0
Short-term debt	8.3	8.3	--	--	--
Junior subordinated debentures payable to a subsidiary trust [1]	280.3	--	--	--	280.3
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	168.6	21.5	48.6	47.7	50.8
Capital lease obligations	7.0	2.0	3.6	1.4	--
Non-cancelable operating leases	129.5	19.3	37.3	26.8	46.1
Fredonia combustion turbines lease [2]	65.3	4.6	8.6	8.3	43.8
Energy purchase obligations	4,988.2	929.4	1,491.0	1,278.2	1,289.6
Financial hedge obligations	20.0	6.2	11.9	1.9	--
Pension funding	45.7	4.3	8.2	9.8	23.4
Total contractual cash obligations	$ 7,966.2	$ 1,034.5	$ 2,161.2	$ 1,713.6	$ 3,056.9

		Amount of Commitment Expiration Per Period			
COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	2005	2006-2007	2008-2009	2010 & Thereafter
Guarantees [3]	$ 131.0	$ --	$ 131.0	$ --	$ --
Liquidity facilities - available [4]	349.5	--	349.5	--	--
Lines of credit - available [5]	53.6	25.4	28.2	--	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 534.6	$ 25.9	$ 508.7	$ --	$ --

1 *In 1997 and 2001, PSE formed Puget Sound Energy Capital Trust I and Puget Sound Energy Capital Trust II, respectively, for the sole purpose of issuing and selling preferred securities (Trust Securities) to investors and issuing common securities to PSE. The proceeds from the sale of Trust Securities were used by the Trusts to purchase Junior Subordinated Debentures (Debentures) from PSE. The Debentures are the sole assets of the Trusts and PSE owns all common securities of the Trusts.*

2 *See "Fredonia 3 and 4 Operating Lease" under "Off-Balance Sheet Arrangements" below.*

3 *In May 2004, InfrastruX signed a three-year credit agreement with a group of banks to provide up to $150 million in financing. Under the credit agreement, Puget Energy is the guarantor of the line of credit. Certain InfrastruX subsidiaries also have certain borrowing capacities for working capital purposes of which Puget Energy is not a guarantor.*

4 *At December 31, 2004, PSE had available a $350 million unsecured credit agreement expiring in June 2007 and a $150 million receivables securitization facility that expires in December 2005. At December 31, 2004, PSE had no amounts of receivables available for sale under its receivables securitization facility. See "Accounts Receivable Securitization Program" under "Off-Balance Sheet Arrangements" below for further discussion. The credit agreement and securitization facility provide credit support for an outstanding letter of credit totaling $0.5 million, thereby effectively reducing the available borrowing capacity under these liquidity facilities to $349.5 million.*

5 *Puget Energy has a $15 million line of credit with a bank. At December 31, 2004, $5.0 million was outstanding, leaving $10.0 million available to borrow under the agreement. Puget Energy reduced the borrowing capacity under this line of credit to $5.0 million on February 1, 2005. InfrastruX has $186.7 million in lines of credit with various banks to fund capital credit requirements of InfrastruX and its subsidiaries. InfrastruX and its subsidiaries had $139.3 million outstanding under their credit agreements and letters of credit of $3.8 million at December 31, 2004, effectively reducing the available borrowing capacity under these lines of credit to $43.6 million.*

Puget Sound Energy. The following are PSE's aggregate contractual and commercial commitments as of December 31, 2004:

Puget Sound Energy CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	Payments Due Per Period 2005	2006-2007	2008-2009	2010 & Thereafter
Long-term debt	$ 2,095.4	$ 31.0	$ 406.0	$ 337.4	$ 1,321.0
Junior subordinated debentures payable to a subsidiary trust [1]	280.3	--	--	--	280.3
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	168.6	21.5	48.6	47.7	50.8
Non-cancelable operating leases	116.4	12.8	31.6	26.0	46.0
Fredonia combustion turbines lease [2]	65.3	4.6	8.6	8.3	43.8
Energy purchase obligations	4,988.2	929.4	1,491.0	1,278.2	1,289.6
Financial hedge obligations	20.0	6.2	11.9	1.9	--
Pension funding	45.7	4.3	8.2	9.8	23.4
Total contractual cash obligations	$ 7,781.8	$ 1,009.8	$ 2,005.9	$ 1,709.3	$ 3,056.8

COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	Amount of Commitment Expiration Per Period 2005	2006-2007	2008-2009	2010 & Thereafter
Liquidity facilities - available [3]	$ 349.5	$ --	$ 349.5	$ --	$ --
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 350.0	$ 0.5	$ 349.5	$ --	$ --

1 *See note 1 above.*
2 *See note 2 above.*
3 *See note 4 above.*

OFF-BALANCE SHEET ARRANGEMENTS

ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

In order to provide a source of liquidity to PSE at an attractive cost, PSE entered into a Receivables Sales Agreement with Rainier Receivables, Inc., a wholly owned subsidiary of PSE in December 2002. Pursuant to the Receivables Sales Agreement, PSE sold all its utility customers' accounts receivable and unbilled utility revenues to Rainier Receivables. Concurrently with entering into the Receivables Sales Agreement, Rainier Receivables entered into a Receivables Purchase Agreement with PSE and a third party. The Receivables Purchase Agreement allows Rainier Receivables to sell the receivables purchased from PSE to the third party. The amount of receivables sold by Rainier Receivables is not permitted to exceed $150 million at any time. However, the maximum amount may be less than $150 million depending on the outstanding eligible amount of PSE's receivables, which fluctuate with the seasonality of energy sales to customers.

The receivables securitization facility is the functional equivalent of a revolving line of credit secured by receivables. In the event Rainier Receivables elects to sell receivables under the Receivables Purchase Agreement, Rainier Receivables is required to pay fees to the purchasers that are comparable to interest rates on a revolving line of credit. As receivables are collected by PSE as agent for the receivables purchasers, the outstanding amount of receivables held by the purchasers declines until Rainier Receivables elects to sell additional receivables to the purchasers.

The receivables securitization facility expires in December 2005, but is terminable by PSE and Rainier Receivables upon notice to the receivables purchasers. At December 31, 2004, Rainier Receivables had fully utilized its $150 million available balance under the receivable securitization facility, and therefore had no additional available balances to be sold under it.

During the years ended December 31, 2004 and 2003, Rainier Receivables sold a cumulative $600.2 million and $348.0 million of receivables, respectively.

FREDONIA 3 AND 4 OPERATING LEASE

PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. The lease has a term expiring in 2011, but can be canceled by PSE at any time. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At December 31, 2004, PSE's outstanding balance under the lease was $56.3 million. The expected residual value under the lease is the lesser of $37.4 million or 60% of the cost of the equipment. In the event the equipment is sold to a third party upon termination of the lease and the aggregate sales proceeds are less than the unamortized value of the equipment, PSE would be required to pay the lessor contingent rent in an amount equal to the deficiency up to a maximum of 87% of the unamortized value of the equipment.

UTILITY CONSTRUCTION PROGRAM

Utility construction expenditures for generation, transmission and distribution are designed to meet continuing customer growth and to improve efficiencies of PSE's energy delivery systems. Construction expenditures, excluding equity Allowance for Funds Used During Construction (AFUDC), were $393.9 million in 2004. Utility construction expenditures in 2005, 2006 and 2007 are expected to be $380 million, $400 million and $384 million, respectively, excluding amounts for new generation resources currently under evaluation. New generation resources under evaluation consist of two separate wind generation projects that are anticipated to be completed in 2005 and 2006, respectively. The first project, if completed in 2005, is anticipated to have a total cost of approximately $200 million. The second project, if completed in 2006, is anticipated to have a total cost range of approximately $300 to $350 million. The proposed utility construction expenditures and new generation resource expenditures, if acquired, are anticipated to be funded with a combination of short-term debt, long-term debt and equity. Construction expenditure estimates, including the new generation resources, are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

NEW GENERATION RESOURCES

In April 2004, PSE completed the purchase of a 49.85% interest in Frederickson 1, a gas-fired electric generating station located in western Washington. The purchase has added $80.8 million in utility plant and approximately 124 MW of electric generation capacity to serve PSE's retail customers. PSE submitted a PCORC in October 2003 to the Washington Commission to recover the cost of the new generating facility and other power costs. The acquisition of Frederickson 1 was approved by the Washington Commission on April 7, 2004 and was also approved by FERC under the Federal Power Act on April 23, 2004.

In September and October 2004, PSE signed two non-binding letters of intent to obtain a 100% ownership interest in both the proposed Wild Horse wind power project (Wild Horse project) and the Hopkins Ridge wind power project (Hopkins Ridge project). The projects are located in central and eastern Washington State. The Wild Horse project is expected to have approximately 100 to 130 wind turbines and generate from 150 to 230 MW of power or 77 average MW, depending on the final design agreement. The Hopkins Ridge project is expected to generate approximately 150 MW of power or 52 average MW. Both projects will require final binding agreements between PSE and the developers. Such agreements are expected to be executed in 2005.

OTHER ADDITIONS

Other property, plant and equipment additions were $15.5 million in 2004. Puget Energy expects InfrastruX's capital additions to be $18.0 million in 2005. Construction expenditure estimates are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for the year ended December 31, 2004 was $456.4 million. During that period, $92.3 million in cash was used for AFUDC and payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $364.1 million or 87.7% of the $415.4 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for 2004. For the year ended December 31, 2003, cash generated from operations was $317.9 million, $90.0 million of which was used for AFUDC and payment of dividends. Therefore, cash flows available for utility construction expenditures and other capital expenditures were $227.9 million, or 77.1% of the $295.7 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for 2003. The overall cash generated from operating activities in 2004 increased $138.5 million compared to 2003. The increase was partially the result of increases in PGA rates in April 2003, October 2003 and October 2004, combined with lower cash paid under the PGA mechanism for liability balances in 2003 for a total positive cash flow of $40.8 million. Cash from operating activities also increased $27.7 million due to higher cash payments received from BPA than provided to customers under the residential exchange program compared to 2003 when PSE provided customers more cash than BPA paid to PSE. In addition, changes in deferred taxes contributed $15.2 million to positive cash flow. In 2004, PSE did not fund the qualified pension plan compared to funding $26.5 million in 2003, which positively impacted cash flow from operating activities. Cash flow from operating activities also improved $27.7 million through recovery of collateral deposits in 2004 compared to a return of collateral deposits in 2003 from energy supply counterparties.

FINANCING PROGRAM

Financing utility construction requirements and operational needs are dependent upon the cost and availability of external funds through capital markets and from financial institutions. Access to funds is dependent upon factors such as general economic conditions, regulatory authorizations and policies, and Puget Energy's and PSE's credit ratings.

RESTRICTIVE COVENANTS

In determining the type and amount of future financing, PSE may be limited by restrictions contained in its electric and gas mortgage indentures, articles of incorporation and certain loan agreements. The goodwill impairment at Puget Energy does not cause any violations of financial covenants at Puget Energy or PSE. Under the most restrictive tests, at December 31, 2004, PSE could issue:

- approximately $281 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $468 million of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest, which PSE exceeded at December 31, 2004;
- approximately $417 million of additional first mortgage bonds under PSE's gas mortgage indenture based on approximately $695 million of gas bondable property available for issuance, subject to an interest coverage ratio limitation of 1.75 times net earnings available for interest, which PSE exceeded at December 31, 2004;
- approximately $486.3 million of additional preferred stock at an assumed dividend rate of 6.625%; and
- approximately $273.2 million of unsecured long-term debt.

At December 31, 2004, PSE had approximately $3.6 billion in electric and gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

CREDIT RATINGS

Neither Puget Energy nor PSE has had any rating downgrade triggers that would accelerate the maturity dates of outstanding debt. However, a downgrade in the companies' credit ratings could adversely affect their ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities. For example, under PSE's revolving credit facility, the spreads over the index and commitment fee increase as PSE's secured long-term debt ratings decline. A downgrade in commercial paper ratings could preclude PSE's ability to issue commercial paper under its current programs. The marketability of PSE commercial paper is currently limited by the A-3/P-2 ratings by Standard & Poor's and Moody's Investors Service. In addition, downgrades in any or a combination of PSE's debt ratings may allow counterparties on a contract by contract basis in the wholesale electric, wholesale gas and financial derivative markets to require PSE to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security.

The ratings of Puget Energy and PSE, as of February 23, 2005, were:

	Ratings	
	Standard & Poor's	Moody's
Puget Sound Energy		
Corporate credit/issuer rating	BBB-	Baa3
Senior secured debt	BBB	Baa2
Shelf debt senior secured	BBB	(P)Baa2
Trust preferred securities	BB	Ba1
Preferred stock	BB	Ba2
Commercial paper	A-3	P-2
Revolving credit facility	*	Baa3
Ratings outlook	Positive	Stable
Puget Energy		
Corporate credit/issuer rating	BBB-	Ba1

* *Standard & Poor's does not rate credit facilities.*

SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

In January 2004, Puget Energy and PSE 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 of:

- common stock of Puget Energy, and
- senior notes of PSE, secured by a pledge of PSE's first mortgage bonds.

On July 15, 2004, PSE issued $200 million in floating rate senior notes under its existing $500 million shelf registration statement, reducing the available balance for issuance under the shelf registration statement to $300 million. The notes float at the three-month LIBOR rate plus 0.30%, (2.37% at December 31, 2004), mature on July 14, 2006, and can be redeemed at par any time after January 15, 2005. PSE used the net proceeds from the sale of the floating rate senior notes to repay outstanding amounts under its commercial paper and accounts receivable securitization programs, including amounts incurred to repay long-term debt, and also used the proceeds to redeem $55 million in principal of first mortgage bonds at a premium of 3.68% on August 14, 2004. It is anticipated that the $200 million in floating rate senior notes will be paid off with a combination of long-term debt and internally generated funds.

During 2004, PSE redeemed the following long-term debt:

- $18.5 million medium term notes with interest rates ranging from 6.07% to 6.10%;
- $30.0 million medium term notes at an interest rate of 7.80% in May 2004;
- $4.2 million conservation trust bonds at an interest rate of 6.45% during 2004;
- $55.0 million medium term notes at an interest rate of 7.35% in August 2004; and
- $50.0 million medium term notes at an interest rate of 7.70% in December 2004.

LIQUIDITY FACILITIES AND COMMERCIAL PAPER

PSE's short-term borrowings and sales of commercial paper are used to provide working capital and funding of utility construction programs.

In May 2004, PSE entered into a three-year, $350 million unsecured credit agreement with a group of banks which replaced its previous $250 million unsecured credit agreement. PSE also has a $150 million receivables securitization program which expires in December 2005. At December 31, 2004, PSE had available $350 million in the unsecured credit agreement and no amounts under its $150 million receivable securitization facility, both of which provide credit support for outstanding commercial paper and outstanding letters of credit. At December 31, 2004, there was $0.5 million outstanding under a letter of credit and no commercial paper outstanding, effectively reducing the available borrowing capacity under these liquidity facilities to $349.5 million.

In May 2004, InfrastruX entered into a three-year, $150 million credit agreement with a group of banks, replacing its previous $150 million credit agreement. Puget Energy is the guarantor of the line of credit. In addition, InfrastruX's subsidiaries have an additional $36.7 million in lines of credit with various banks, for a total capacity for InfrastruX and its subsidiaries of $186.7 million under their line of credit agreements. Borrowings available for InfrastruX are used to fund acquisitions and working capital requirements of InfrastruX and its subsidiaries. At December 31, 2004, InfrastruX and its subsidiaries had $139.3 million outstanding under their credit agreements and letters of credit of $3.8 million, effectively reducing the available borrowing capacity under these lines of credit to $43.6 million.

Puget Energy has a $15 million credit agreement expiring in May 2006 with a bank. On February 1, 2005, Puget Energy reduced the borrowing capacity of this credit agreement to $5.0 million. Under the terms of the agreement, Puget Energy pays a floating interest rate on borrowings based on LIBOR. The interest rate is set for one, two, or three-month periods at the option of Puget Energy with interest due at the end of each period. Puget Energy also pays a commitment fee on any unused portion of the credit facility. Puget Energy had $5.0 million outstanding under the credit agreement at December 31, 2004.

STOCK PURCHASE AND DIVIDEND REINVESTMENT PLAN

Puget Energy has a Stock Purchase and Dividend Reinvestment Plan pursuant to which shareholders and other interested investors may invest cash and cash dividends in shares of Puget Energy's common stock. Since new shares of common stock may be purchased directly from Puget Energy, funds received may be used for general corporate purposes. Puget Energy issued common stock from the Stock Purchase and Dividend Reinvestment Plan of $15.2 million (681,491 shares) in 2004 compared to $15.5 million (721,340 shares) in 2003. The proceeds from sales of stock under these plans are used for general corporate needs.

COMMON STOCK OFFERING PROGRAMS

To provide additional financing options, Puget Energy entered into agreements in July 2003 with two financial institutions under which Puget Energy may offer and sell shares of its common stock from time to time through these institutions as sales agents, or as principals. Sales of the common stock, if any, may be made by means of negotiated transactions or in transactions that may be deemed to be "at-the-market" offerings as defined in Rule 415 promulgated under the Securities Act of 1933, including in ordinary brokers' transactions on the New York Stock Exchange at market prices.

OTHER

TENASKA DISALLOWANCE

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a disallowance of $25.6 million for the PCA 1 period (July 1, 2002 through June 30, 2003), which was recorded by PSE as a Purchased Electricity expense in the second quarter 2004. The order also established guidelines for future recovery of Tenaska costs. The amounts were determined to be a $25.6 million disallowance for the PCA 1 period and an estimated disallowance of $11.3 million for the PCA 3 period (July 1, 2004 to June 30, 2005), based upon applying the Washington Commission's methodology of 50% disallowance on the return on the Tenaska regulatory asset due to projected costs exceeding the benchmark during the period. For the PCA 3 period, approximately $5.6 million was disallowed in the period July 1, 2004 through December 31, 2004, primarily as a reduction to Electric Operating Revenue. While the Washington Commission did not expressly address the disallowance for the PCA 2 period (July 1, 2003 through June 30, 2004), PSE estimated the disallowance for the PCA 2 period to be approximately $12.2 million if the Washington Commission were to follow the same methodology as they have ordered for the PCA 3 period. Therefore, PSE recorded a $12.2 million disallowance to Purchased Electricity expense in the second quarter 2004 for the 50% disallowance of the return on the Tenaska regulatory asset in accordance with the Washington Commission's methodology discussed in its order of May 13, 2004 for a cumulative impact on earnings of $43.4 million in 2004 for the PCA 1, PCA 2 and PCA 3 periods. As a result of the disallowance recorded, the PCA customer deferral was expensed and a reserve was established for amounts not previously deferred under the PCA mechanism. The reserve balance as of December 31, 2004 was $3.2 million, which is expected to be utilized in 2005 as excess power costs are shared through the PCA mechanism.

PSE filed the PCA 2 period compliance filing in August 2004 and received an order from the Washington Commission on February 23, 2005. In the PCA 2 compliance order, the Washington Commission approved the Washington

Commission staff's recommendation for an additional return related to the Tenaska regulatory asset in the amount of $6.1 million related to the period July 1, 2003 through December 31, 2003. Washington Commission staff's recommendation was opposed by certain other parties. This amount alters the PCA deferral and is subject to reconsideration and appeal by other parties. Parties have 10 days from February 23, 2005 to file for reconsideration and 30 days to appeal the order. Once the statutory appeal process has concluded and the Washington Commission issues its final order, PSE will determine if recording a regulatory asset is appropriate.

In the May 13, 2004 order, the Washington Commission established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

Below is a summary of the Tenaska disallowances by quarter through December 31, 2004:

(DOLLARS IN MILLIONS) QUARTER ENDING	7/02 - 6/03 PCA 1 (ordered/final)	7/03 - 6/04 PCA 2 (estimated)	7/04 - 12/04 PCA 3 (estimated)	Total
June 30, 2004	$25.6	$12.2	$ --	$37.8
September 30, 2004	--	--	2.8	2.8
December 31, 2004	--	--	2.8	2.8
Total	$25.6	$12.2	$5.6	$43.4

The Washington Commission guidelines for determining future recovery of the Tenaska costs (gas costs, recovery of the Tenaska regulatory asset and return on the Tenaska regulatory asset) are as follows:

1. The Washington Commission will determine if PSE's gas purchasing plan and gas purchases for Tenaska are prudent through the PCA compliance filings.
2. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, and if PSE's actual Tenaska costs fall at or below the benchmark, it will fully recover its Tenaska costs.
3. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, but its actual Tenaska costs exceed the benchmark, PSE will only recover 50% of the lesser of:
   a) actual Tenaska costs that exceed the benchmark; or
   b) the return on the Tenaska regulatory asset.
4. If PSE's gas purchasing plan or gas purchases are found to be imprudent in a future proceeding, PSE risks disallowance of any and all Tenaska costs.

The Washington Commission confirmed that if the Tenaska gas costs are deemed prudent, PSE will recover the full amount of actual gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded. The projected costs and projected benchmark costs for Tenaska have been updated as of December 31, 2004 to reflect higher forward gas prices and are as follows:

(DOLLARS IN MILLIONS)	2005	2006	2007	2008	2009	2010	2011
Projected Tenaska costs *	$ 194.5	$ 197.2	$ 189.0	$ 180.3	$ 170.3	$ 162.9	$ 170.0
Projected Tenaska benchmark costs	159.7	167.9	175.2	182.2	189.5	197.2	213.8
Over (under) benchmark costs	$ 34.8	$ 29.3	$ 13.8	$ (1.9)	$ (19.2)	$ (34.3)	$ (43.8)
Projected 50% disallowance based on Washington Commission methodology	$ 10.5	$ 8.8	$ 5.8	$ 1.6	$ --	$ --	$ --

* *Projection will change based on market conditions of gas and replacement power costs.*

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

The following discussion summarizes the status as of the date of this report of ongoing proceedings in which PSE is a party relating to the Western power markets. PSE intends to vigorously defend against each of these cases and does not expect the ultimate resolution of these proceedings in the aggregate to have a material adverse impact on the financial condition, results of operations or liquidity of the Company. However, there can be no assurances in that regard because litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no guarantee that these proceedings, either individually or in the aggregate, will not materially and adversely affect PSE's financial condition, results of operations or liquidity.

1. **California Receivable and California Refund Proceeding.** In 2001, PG&E and Southern California Edison failed to pay the California Independent System Operator Corporation (CAISO) and the California PX for energy purchases. The CAISO in turn failed to pay various energy suppliers, including PSE, for energy sales made by PSE into the California energy market during the fourth quarter 2000. Both PG&E and the California PX filed for bankruptcy in 2001, further constraining PSE's ability to receive payments due to bankruptcy court controls placed on the distribution of funds by the California PX and the escrow of funds owed by PG&E for purchases during the fourth quarter 2000 are owed by the California PX.

   a. ***California Refund Proceeding.*** On July 25, 2001, FERC ordered an evidentiary hearing (Docket No. EL00-95) to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CAISO and the California PX during the period October 2, 2000 through June 20, 2001 (refund period). The CAISO continues its efforts to prepare revised settlement statements based on newly recalculated costs and charges for spot market sales to California during the refund period and currently estimates that it will determine "who owes what to whom" in early 2005. On September 2, 2004, FERC issued an order selecting Ernst & Young LLP as the independent auditor of fuel cost allowance claims made by sellers, including PSE. A review of that claim is pending, awaiting further guidance from FERC.

      Many of the numerous orders that FERC issued in Docket No. EL00-95 are on appeal and have been consolidated before the United States Court of Appeals for the Ninth Circuit as a result of a case management conference conducted on September 21, 2004. FERC filed the record on November 22, 2004. The Ninth Circuit ordered on October 22, 2004 that briefing proceed in two rounds. The first round is limited to three issues: (1) which parties are subject to FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; (3) which categories of transactions are subject to refunds.

      Procedures will be established for the remaining issues, if necessary, after the court's disposition of the first round of issues. Following a second case management conference on November 9, 2004, the Ninth Circuit consolidated certain petitions for review for briefing of the first round of issues to be completed by March 1, 2005 and set oral argument hearings for April 12 and 13, 2005. Opening briefs were filed on December 29, 2004. PSE joined the brief of the Competitive Supplier Group, which argued that FERC has proposed to require payment of refunds without proper notice to sellers, without proper limits on the type of transactions affected and without a finding that the transactions subject to refund in fact produced prices that were just and reasonable. Respondents' briefs in support of FERC were due February 9, 2005.

   b. ***CAISO Receivable***. PSE has a bad debt reserve and a transaction fee reserve applied to the CAISO receivable, such that PSE's net receivable from the CAISO as of December 31, 2004 is approximately \$21.3 million. PSE estimates the range for the receivable to be between \$21.3 million and \$22.4 million, which includes estimated credits for fuel and power purchase costs and interest. In its October 16, 2003 Order on Rehearing in this docket, FERC expressly adopted and approved a stipulation that confirmed that two of PSE's "non-spot market" transactions are not subject to mitigation in the Refund Proceeding. On October 17, 2003, PSE formally presented CAISO with a request that payment be made on these amounts. The CAISO responded to the letter on November 13, 2003, expressing an unwillingness to take the issue up separately or in advance of its cost re-run activities. PSE continues to pursue the issue in filings through FERC processes.

On May 6, 2004, the Los Angeles Department of Water and Power filed a motion at FERC in Docket No. EL00-95 requesting that FERC issue an order permitting monies to be disbursed from the California PX Settlement Clearing Account and an escrow account be established as part of PG&E's bankruptcy proceeding. The bulk of the monies owed by the CAISO, including the monies owed to PSE, are held in those two accounts. PSE filed an answer in support of the motion on May 21, 2004, and awaits an order from FERC.

2. **Pacific Northwest Refund Proceeding.** In October 2000, PSE filed a complaint at FERC (Docket No. EL01-10) against "all jurisdictional sellers" in the Pacific Northwest seeking prospective price caps consistent with any result FERC supplied for the California markets. FERC dismissed PSE's complaint on December 15, 2000, although PSE filed for rehearing in January 2001. When FERC issued its June 19, 2001 order in Docket No. EL00-95, imposing west-wide price constraints on energy sales, PSE moved to withdraw its rehearing request and its complaint in Docket No. EL01-10, on the basis that the relief PSE sought was fully provided. Various parties, including the Port of Seattle and the cities of Seattle and Tacoma, moved to intervene in the proceeding. They asserted the ability to adopt PSE's complaint to obtain retroactive refunds for numerous transactions, including many that were not within the scope of the PSE complaint. The proceeding became commonly referenced as the "Pacific Northwest Refund Proceeding," despite the fact that the original complainant, PSE, did not seek retroactive refunds. A preliminary evidentiary hearing was held in September 2001, and an Administrative Law Judge recommendation against refunds followed. In December 2002, FERC issued an order permitting additional discovery and the submission of any additional evidence (parallel to the order issued in the California Refund Proceeding) that reopened the matter to permit parties to introduce any evidence they claimed to have of market manipulation. A few parties made filings, asserting market manipulation in early March 2003, and numerous parties, including PSE, responded to those allegations in late March 2003. On June 25, 2003, FERC issued an order terminating the proceeding, largely on procedural, jurisdictional and equitable grounds. Various parties filed rehearing requests on July 25, 2003. On November 10, 2003, FERC affirmed an order terminating the Pacific Northwest Refund Proceeding, (Docket No. EL01-10), largely on procedural, jurisdictional and equitable grounds. Seven petitions for review, including PSE's, are now pending before the United States Court of Appeals for the Ninth Circuit. Opening briefs were filed on January 14, 2005. PSE's opening brief addressed procedural flaws underlying the action of FERC. Specifically, PSE argued that because PSE's complaint in the underlying docket was withdrawn as a matter of law on July 9, 2001, FERC erred in relying on it to serve as the basis to initiate a "preliminary" investigation into whether refunds for individually negotiated bilateral transactions in the Pacific Northwest were appropriate. Briefing is expected to be completed in the first half of 2005.

3. **Orders to Show Cause.** On June 25, 2003, FERC issued two show cause orders pertaining to its western market investigations that commenced individual proceedings against many sellers. One show cause order (Docket Nos. EL03-180, et seq.) sought to investigate approximately 26 entities that allegedly had potential "partnerships" with Enron. PSE was not named in that show cause order. In an order dismissing many of the already-named respondents in the "partnerships" proceeding on January 22, 2004, FERC stated that it did not intend to proceed further against other parties.

   The second show cause order (Docket Nos. EL03-137, et seq.) named PSE (Docket No. EL03-169) and approximately 54 other entities that allegedly had engaged in potential "gaming" practices in the CAISO and California PX markets. PSE and FERC staff filed a proposed settlement of all issues pending against PSE in those proceedings on August 28, 2003. The proposed settlement, which admits no wrongdoing on the part of PSE, would result in a payment of $17,092 to settle all claims. FERC approved the settlement on January 22, 2004. The California parties filed for rehearing of that order, repeating arguments that had already been addressed by FERC. On March 17, 2004, PSE filed a motion to dismiss the California parties' rehearing request, and awaits FERC action on that motion.

4. **Port of Seattle Suit.** On May 21, 2003, the Port of Seattle commenced suit in federal court in Seattle against 22 energy sellers, alleging that their conduct during 2000 and 2001 constituted market manipulation, violated antitrust laws and damaged the Port of Seattle. The Port had a contract to purchase its energy supply from PSE at the time. The Port's contract linked the price of the energy sold to the Port to an index price for energy sold at wholesale at the Mid-Columbia trading hub. The Port alleged that the Mid-Columbia price was intentionally affected improperly by the defendants, including PSE, and alleges damages of over $30 million. On May 12, 2004, the district court dismissed the lawsuit. The Port of Seattle filed an appeal to the United States Court of Appeals for the Ninth Circuit, and on September 13, 2004, filed a brief in the Ninth Circuit arguing that the district court erred in dismissing its claims. Responses to the Port's brief were filed November 2, 2004. The parties await oral argument to be scheduled.

5. **Wah Chang v. Avista Corp., PSE and others.** In June 2004, Puget Energy and PSE were served a federal summons and complaint by Wah Chang, an Oregon company. Wah Chang claims that during 1998 through 2001 the Company and other energy companies (and in a separate complaint, energy marketers) engaged in various fraudulent and illegal activities including the transmittal of electronic wire communications to transmit false or misleading information to manipulate the California energy market. The claims include submitting false information such as energy schedules and bids to the California PX, CAISO, electronic trading platforms and publishers of energy indexes, alleges damages of not less than $30 million and seeks treble and punitive damages, attorneys' fees and costs. The complaint is similar to the allegations made by the Port of Seattle currently on appeal in the Ninth Circuit. The Judicial Panel on Multi District Litigation consolidated this case with another pending Multi District case and transferred it to Federal District Court in San Diego on August 20, 2004. The defendants in both cases filed motions to dismiss on October 25, 2004. Wah Chang opposed the motions to dismiss, and replies in support of the motions to dismiss were filed on January 12, 2005. On February 11, 2005, approximately three weeks after hearing oral argument, the Court dismissed both cases on the grounds that FERC has the exclusive jurisdiction over plaintiff's claims and the filed rate doctrine and Federal preemption barred the court from hearing the plaintiff's claims.

6. **California Litigation.** *Attorney General Cases.* On May 31, 2002, FERC conditionally dismissed a complaint filed on March 20, 2002 by the California Attorney General in Docket No. EL02-71 that alleged violations of the FPA by FERC and all sellers (including PSE) of electric power and energy into California. The complaint asserted that FERC's adoption and implementation of market rate authority was flawed and, as a result, individual sellers such as PSE were liable for sales of energy at rates that were "unjust and unreasonable." The condition for dismissal was that all sellers refile transaction summaries of sales to (and, after a clarifying order issued on June 28, 2001, purchases from) certain California entities during 2000 and 2001. PSE refiled such transaction summaries on July 1 and July 8, 2002. The order of dismissal went on appeal to the Ninth Circuit Court of Appeals. On September 9, 2004, the Ninth Circuit issued a decision on the California Attorney General's challenge to the validity of FERC's market-based rate system (*Lockyer v. FERC*). This case was originally presented to FERC. The Ninth Circuit upheld FERC's authority to authorize sales of electric energy at market based rates, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with FERC to be integral to a market-based rate tariff. The California parties, among others, have interpreted the decision as providing authority to FERC to order refunds for different time frames and based on different rationales than are currently pending in the California Refund Proceedings, discussed above in "California Refund Proceeding." The decision itself defers the question of whether to seek refunds to FERC. PSE, along with other defendants in the proceeding, sought rehearing of the Ninth Circuit's decision on October 25, 2004. The Ninth Circuit has yet to issue an order on the rehearing request. Because the current Ninth Circuit decision may open new periods of transactions to refund claims under new theories, PSE cannot predict the scope, nature or ultimate resolution of this case. That additional uncertainty may make the outcomes of certain other western energy market cases less predictable than previously anticipated.

In addition, the day after the initial FERC decision in the *Lockyer* case, the California Attorney General filed similar claims in state court in California, including one suit against PSE. These complaints alleged that the wholesale seller defendants in the California energy market engaged in anti-competitive behavior in violation of the California Business Practices Act for sales in the California energy market (*Lockyer v. Transalta).* The complaint asserted that each such "violation" subjects PSE to a fine of up to $2,500 plus an award of attorneys' fees and asserts that there were "thousands" of such violations. Those cases were removed to federal court and dismissed. On October 12, 2004, the Ninth Circuit issued a decision affirming the dismissal of all 13 complaints filed by the California Attorney General, including a complaint against PSE. The Ninth Circuit decision concluded that the opinions in *People of the State of California ex rel. Bill Lockyer v. Dynegy, et al.* and *Public Utility District No. 1 of Snohomish County v. Dynegy Power Marketing, Inc.*, decided earlier this year by the Ninth Circuit, controlled the outcome of the matters and warranted dismissal. Because no party sought rehearing or filed a petition for certiorari to the Supreme Court of the United States, the Ninth Circuit's order is the final determination of this matter.

California Class Actions. In May 2002, PSE was served with two cross-complaints, by Reliant Energy Services and Duke Energy Trading & Marketing, respectively, in six consolidated class actions filed in Superior Court in San Diego, California. Plaintiffs in the lawsuit seek, among other things, restitution of all funds acquired by means that violate the law and payment of treble damages, interest and penalties. The cross-complaints asserted essentially that the cross-defendants, including PSE, were also participants in the California energy market at the relevant times, and that any remedies ordered against some market participants should be ordered against all. Reliant and Duke also seek indemnification and conditional relief as buyers in transactions involving cross-defendants should the plaintiffs prevail. The case was removed to federal court and some of the newly added defendants, including PSE, moved to dismiss the action. In December 2002, the federal district court remanded the proceeding to state court, an action which Duke and Reliant later appealed to the Ninth Circuit. The appeal stayed further action in the state court proceeding pending the outcome of the appeal. The cross-complaints and the addition of the 40 new defendants raised issues of foreign sovereign immunity, jurisdiction and indemnity in the case, all of which are now part of the appeal. In June 2003, PSE and other defendants filed motions to respond to the indemnity issues. On May 13, 2004, the Ninth Circuit issued an order granting PSE status as a cross-appellant but did not permit PSE to participate in the oral argument heard on June 14, 2004. On December 8, 2004, the Ninth Circuit issued an opinion affirming the district court's decision to remand the case to state court. Powerex filed a petition for rehearing which argues that although not immune from suit, as a government entity it should be allowed to litigate in federal, not state court. Powerex's petition for rehearing stays issuance of the mandate to remand pending the outcome of its rehearing request.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with Generally Accepted Accounting Principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following accounting policies represent those that management believes are particularly important to the financial statements and that require the use of estimates, assumptions and judgment to describe matters that are inherently uncertain.

REVENUE RECOGNITION

Utility revenues are recognized when the basis of service is rendered, which includes estimates to determine amounts relating to services rendered but not billed. Unbilled electricity revenue is determined by taking MWh generated and purchased less estimated system losses and billed MWh plus unbilled MWh balance at the last true-up date. The estimated system loss percentage for electricity is determined by reviewing historical billed MWh to generated and purchased MWh. The estimated unbilled MWh balance is then multiplied by the estimated average revenue per MWh. Unbilled gas revenue is determined by taking therms delivered to PSE less estimated system losses, prior month unbilled therms and billed therms. The estimated system loss percentage for gas is determined by reviewing historical billed therms to therms delivered to customers. The estimated current month unbilled therms is then multiplied by estimated average rate schedule revenue per therm. Non-utility revenue is recognized when services are performed, upon the sale of assets, or on a percentage of completion basis for fixed-price contracts. The recognition of revenue is in conformity with Generally Accepted Accounting Principles, which requires the use of estimates and assumptions that affect the reported amounts of revenue.

The following table represents the sensitivity of the estimate of system losses for both electricity and gas in calculating unbilled revenues assuming an additional 0.1% increase in the estimated system loss factor since the last annual true-up:

	GAS REVENUE DECREASE (MILLIONS)	ELECTRIC REVENUE DECREASE (MILLIONS)
0.1% increase in loss factor	$0.4	$0.6

REGULATORY ACCOUNTING

As a regulated entity of the Washington Commission and FERC, PSE prepares its financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The application of SFAS No. 71 results in differences in the timing and recognition of certain revenues and expenses in comparison with businesses in other industries. The rates that are charged by PSE to its customers are based on cost base regulation reviewed and approved by the Washington Commission and FERC. Under the authority of these commissions, PSE has recorded certain regulatory assets and liabilities at December 31, 2004 in the amount of $645.3 million and $185.7 million, respectively, and regulatory assets and liabilities of $610.5 million and $176.7 million, respectively, at December 31, 2003.. PSE expects to fully recover these regulatory assets and liabilities through its rates. If future recovery of costs ceases to be probable, PSE would be required to write off these regulatory assets and liabilities. In addition, if at some point in the future PSE determines that it no longer meets the criteria for continued application of SFAS No. 71, PSE could be required to write off its regulatory assets and liabilities.

Also encompassed by regulatory accounting and subject to SFAS No. 71 are the PCA and PGA mechanisms. The PCA and PGA mechanisms mitigate the impact of commodity price volatility upon the Company, and are approved by the Washington Commission. The PCA mechanism provides for a sharing of costs and benefits that are graduated over four levels of power cost variances with an overall cap of $40 million (+/-) plus 1% of the excess over the $40 million cap over the four-year period ending June 30, 2006. The PCA mechanism will continue after July 1, 2006, within certain sharing bands. See Item 1 – Business – Regulation and Rates – Electric Regulation and Rates for further discussion regarding the PCA mechanism. The PGA mechanism passes through to customers increases and decreases in the cost of natural gas supply. PSE expects to fully recover these regulatory assets through its rates. However, both mechanisms are subject to regulatory review and approval by the Washington Commission on a periodic basis.

DERIVATIVES

Puget Energy uses derivative financial instruments primarily to manage its energy commodity price risks, and may enter into certain financial derivatives to manage interest rate risk. Derivative financial instruments are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149. Accounting for derivatives continues to evolve through guidance issued by the Derivatives Implementation Group (DIG) of the Financial Accounting Standards Board (FASB). To the extent that changes by the DIG modify current guidance, including the normal purchases and normal sales determination, the accounting treatment for derivatives may change.

To manage its electric and gas portfolios, Puget Energy enters into contracts to purchase or sell electricity and gas. These contracts are considered derivatives under SFAS No. 133 unless a determination is made that they qualify for normal purchases and normal sales exception. If the exception applies, those contracts are not marked-to-market and are not reflected in the financial statements until delivery occurs.

The availability of the normal purchases and normal sales exception to specific contracts is based on a determination that a resource is available for a forward sale and similarly a determination that at certain times existing resources will be insufficient to serve load. This determination is based on internal models that forecast customer demand and generation supply. The models include assumptions regarding customer load growth rates, which are influenced by the economy, weather, the impact of customer choice and resource availability. The critical assumptions used in the determination of the normal purchases and normal sales exception are consistent with assumptions used in the general planning process.

Energy and financial contracts that are considered derivatives may be eligible for designation as cash flow hedges. If a contract is designated as a cash flow hedge, the change in its market value is generally deferred as a component of other comprehensive income until the transaction it is hedging is completed. Conversely, the change in the market value of derivatives not designated as cash flow hedges is recorded in current period earnings.

PSE values derivative instruments based on daily quoted prices from numerous independent energy brokerage services. When external quoted market prices are not available for derivative contracts, PSE uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis.

PENSION AND OTHER POSTRETIREMENT BENEFITS

Puget Energy has a qualified defined benefit pension plan covering substantially all employees of PSE. For 2004, 2003 and 2002, qualified pension income of $8.0 million, $12.9 million and $17.7 million, respectively, was recorded in the financial statements. Of these amounts, approximately 63.3%, 67.0% and 66.8% offset utility operations and maintenance expense in 2004, 2003 and 2002, respectively, and the remaining amounts were capitalized.

PSE's pension and other postretirement benefits income or costs are dependent on several factors and assumptions, including design of the plan, timing and amount of cash contributions to the plan, earnings on plan assets, discount rate, expected long-term rate of return and health care cost trends. Changes in any of these factors or assumptions will affect the amount of income or expense that Puget Energy records in its financial statements in future years and also its projected benefit obligation.

The follow table reflects the estimated sensitivity associated with a change in certain actuarial assumptions (each assumption change is presented mutually exclusive of other assumption changes):

	Change in Assumption	Impact on Projected Benefit Obligation increase (decrease)		Impact on 2004 Pension Income increase (decrease)	
(Dollars in Thousands)		Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Increase in discount rate	50 basis points	$ (20,548)	$ (3,635)	$ 1,261	$ 354
Decrease in discount rate	50 basis points	22,595	3,891	(48)	(377)
Increase in return of plan assets	50 basis points	*	*	2,370	71
Decrease in return on plan assets	50 basis points	*	*	(2,370)	(71)

* *Calculation not applicable.*

Qualified pension income is expected to decline to $2.5 million in 2005 as a result of lower actual returns on pension assets during the last three years and declining expected rates of return on pension fund assets. During 2004, PSE made no cash contributions to the qualified defined benefit plan and expects to make no contributions in 2005.

GOODWILL AND INTANGIBLES (PUGET ENERGY ONLY)

On January 1, 2002, SFAS No. 142, "Goodwill and Other Intangible Assets," became effective and as a result Puget Energy ceased amortization of goodwill. Puget Energy performs an annual impairment review to determine if any impairment exists. In performing the goodwill impairment test, Puget Energy compares the present value of the future cash flows of estimated earnings of InfrastruX which reflects prospective market price information from prospective buyers to the adjusted carrying value of recorded equity. If goodwill is determined to have an impairment, Puget Energy will record in the period of determination an impairment charge to earnings.

Intangibles with finite lives are amortized based on the expected pattern of use or on a straight-line basis over the expected periods to be benefited. The goodwill and intangibles recorded on the balance sheet of Puget Energy are the result of acquisition of companies by InfrastruX. During 2004, Puget Energy recorded a non-cash goodwill impairment charge of $91.2 million, or $76.6 million after-tax and minority interest. As a result, the goodwill balance at December 31, 2004 was $43.5 million. Intangible assets have not been impaired and the balance at December 31, 2004 was $16.7 million.

CALIFORNIA RESERVE

PSE operates within the western wholesale market and has made sales into the California energy market. At December 31, 2000, PSE's receivables from the CAISO and other counterparties, net of reserves, were $41.8 million. PSE received the majority of the partial payments for sales made in the fourth quarter 2000 in the first quarter 2001 and has since received a small amount of payments. At December 31, 2004, such receivables, net of reserves, were approximately $21.3 million.

During 2003, FERC issued an order in the California Refund Proceeding adopting in part and modifying in part FERC's earlier findings by the Administrative Law Judge. Based on the order, PSE has determined that the receivables balance at December 31, 2004 is collectible from the CAISO.

NEW ACCOUNTING PRONOUNCEMENTS

In December 2004, FASB issued SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), which revises SFAS No. 123, "Accounting For Stock-Based Compensation." SFAS No. 123R requires companies that issue share-based payment awards to employees for goods or services to recognize as compensation expense, the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS No. 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS No. 123R is effective for reporting periods beginning after June 15, 2005. The Company is currently evaluating what impact the application of SFAS No. 123R will have on its operations. The Company had adopted the fair value provisions of SFAS No. 123 "Accounting for Stock Based Compensation" in January 2003.

In December 2004, FASB issued FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" (FSP No. 109-1). FSP No. 109-1 states that the staff position related to deductions as a result of the American Jobs Creation Act (the Act) should be treated as a "special deduction", as described in SFAS No. 109, "Accounting For Income Taxes" and therefore has no effect on deferred tax assets or liabilities existing at the enactment date. The Company is currently evaluating the impact of FSP No. 109-1 (which was effective upon issuance) and any deduction available under the Act. Any deduction available, if determined, is applicable to the Company's 2005 tax year.

On May 19, 2004, FASB issued FASB Staff Position (FSP) No. 106-2 "Accounting and Disclosure Requirements Related to Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare Prescription Drug and Modernization Act which was signed into law in December 2003. The law provides a subsidy for plan sponsors that provide prescription drug benefits to Medicare beneficiaries that are equivalent to the Medicare Part D plan. Based on an actuarial assessment, PSE will not be eligible for such subsidies, thus FSP No. 106-2 will have no impact on PSE's retiree medical plans.

The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) at its July 2003 meeting came to a consensus concerning EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03." The consensus reached was that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes are reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Based on the guidance by EITF No. 03-11, the Company determined that its non-trading derivative instruments should be reported net and implemented this treatment effective January 1, 2004. As a result of the implementation, Electric Revenue and Purchased Electricity Expense both decreased $108.7 million in 2003 and $77.1 million in 2002, respectively, with no impact on financial position or net income.

In March 2004, the EITF came to a consensus concerning EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies." The consensus reached was that an investment in a limited liability company should be accounted for using the equity method for investments greater than 3% to 5%. The adoption of EITF No. 03-16 is effective for reporting periods beginning after June 15, 2004, with any adjustments being accounted for as a cumulative effect of a change in accounting principle. The Company reviewed its investments and determined one investment held by PSE met the criteria established in EITF No. 03-16.

In May 2003, FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 establishes the requirements for classifying and measuring as liabilities certain financial instruments that embody obligations to redeem the financial instruments by the issuer. The adoption of SFAS No. 150 is effective with the first fiscal year or interim period beginning after June 15, 2003. However, on November 5, 2003 FASB deferred for an indefinite period certain mandatorily redeemable noncontrolling interests associated with finite-lived subsidiaries. The Company does not have any noncontrolling interest in finite-lived subsidiaries and therefore is not affected by the deferral. Prior periods will not be restated for the new presentation.

SFAS No. 150 requires the Company to classify its mandatorily redeemable preferred stock as liabilities. As a result, the corresponding dividends on the mandatorily redeemable preferred stock are classified as interest expense on the income statement with no impact on net income.

In January 2003, FASB issued Interpretation No. 46, “Consolidation of Variable Interest Entities” (FIN 46), as further revised in December 2003 with FIN 46R, which clarifies the application of Accounting Research Bulletin No. 51, “Consolidated Financial Statements,” to certain entities in which equity investors do not have a controlling interest or sufficient equity at risk for the entity to finance its activities without additional financial support. FIN 46R requires that if a business entity has a controlling financial interest in a variable interest entity, the financial statements must be included in the consolidated financial statements of the business entity. The adoption of FIN 46R for all interests in variable interest entities created after January 31, 2003 was effective immediately. For variable interest entities created before February 1, 2003, it was effective July 1, 2003. The adoption of FIN 46R was effective March 31, 2004. The Company has evaluated its contractual arrangements and determined PSE’s 1995 conservation trust off-balance sheet financing transaction meets this guidance, and therefore it was consolidated in the third quarter 2003. As a result, electricity revenues for 2003 increased $5.7 million, while conservation amortization and interest expense increased by the corresponding amount with no impact on earnings. FIN 46R also impacted the treatment of the Company’s mandatorily redeemable preferred securities of a wholly owned subsidiary trust holding solely junior subordinated debentures of the corporation (trust preferred securities). Previously, these trust-preferred securities were consolidated into the Company’s operations. As a result of FIN 46R, these securities have been deconsolidated and were classified as junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities (junior subordinated debt) in the fourth quarter 2003. This change had no impact on the Company’s results of operations. The Company also evaluated its purchase power agreements and determined that three counterparties may be considered variable interest entities. As a result, PSE submitted requests for information to those parties; however, the parties have refused to submit to PSE the necessary information for PSE to determine whether they meet the requirements of a variable interest entity. PSE also determined that it does not have a contractual right to such information. PSE will continue to submit requests for information to the counterparties on a quarterly basis to determine if FIN 46R is applicable.

For the three purchase power agreements that may be considered variable interest entities under FIN 46R, PSE is required to buy all the generation from these plants, subject to displacement by PSE, at rates set forth in the purchase power agreements. If at any time the counterparties cannot deliver energy to PSE, PSE would have to buy energy in the wholesale market at prices which could be higher or lower than the purchase power agreement prices. PSE’s Purchased Electricity expense for 2004 and 2003 for these three entities was $251.2 million and $273.9 million, respectively.

In June 2001, FASB issued SFAS No. 143, “Accounting for Asset Retirement Obligations,” (SFAS No. 143), which is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company adopted the new rules on asset retirement obligations on January 1, 2003. As a result, the Company recorded a $0.2 million charge to income for the cumulative effect of this accounting change.

In November 2004, FASB reached a decision concerning a proposed interpretation of SFAS No. 143 titled “Accounting for Conditional Asset Retirement Obligations.” The proposed interpretation addresses the issue of whether SFAS No. 143 requires an entity to recognize a liability for a legal obligation to perform asset retirement when the asset retirement activities are conditional on a future event, and if so, the timing and valuation of the recognition. The decision reached by FASB was that there are no instances where a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation. This, if part of the final issued interpretation, could potentially have an impact on the Company as assets that were previously considered outside the scope of SFAS No. 143 may be subject to the terms of the proposed interpretation. FASB indicated that the final interpretation is anticipated to be issued in the first quarter 2005, with an effective date for fiscal years ending after December 15, 2005, and with any adjustment accounted for as a cumulative effect of an accounting change. The Company is currently evaluating what impact this proposed interpretation may have on the Company if issued.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ENERGY PORTFOLIO MANAGEMENT

The regulatory mechanisms of the PGA and the PCA mitigate the impact of commodity price volatility on the Company. The PGA mechanism passes through increases and decreases in the cost of natural gas supply to customers. The PCA mechanism provides for a sharing of costs and benefits that are graduated over four levels of power cost variances with an overall cap of $40 million (+/-) plus 1% of the excess over the $40 million cap over the four-year period ending June 30, 2006.

The Company is focused on commodity price exposure and risks associated with volumetric variability in the gas portfolio and electric portfolio for its customers. Gas and electric portfolio exposure is managed in accordance with Company polices and procedures. The Risk Management Committee, which is composed of Company officers, provide policy-level and strategic direction for management of the energy portfolio. The Audit Committee of the Company's Board of Directors periodically assesses risk management policies.

The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy risk management function monitors and manages these risks using analytical models and tools. The Company manages its energy supply portfolio to achieve three primary objectives:

- ensure that physical energy supplies are available to serve retail customer requirements;
- manage portfolio risks to limit undesired impacts on the Company's costs; and
- maximize the value of the Company's energy supply assets.

The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

The risk metrics the Company employs are aimed at assessing exposure for the purposes of developing strategies to reduce the potential exposure on a cost-effective basis in regulated utility gas and electric portfolios. Specifically, the amount of risk exposure is defined by time period and by portfolio. It is determined through statistical methods aimed at forecasting risk.

The energy risk management staff models forecasted load requirements and expected resource availability, and projects the net deficit or surplus position resulting from any imbalance between load requirements and existing resources. However, the portfolios are subject to major sources of variability (e.g., hydroelectric generation, outage risk, regional economic factors, temperature-sensitive retail sales and market prices for gas and power supplies). At certain times, these sources of variability can mitigate portfolio imbalances and at other times they can exacerbate portfolio imbalances. Because of the volumetric and cost variability within the electric and gas portfolios, the Company runs market simulations to model potential risk scenarios. In this way, strategies can be developed to address the expected case as well as other potential scenarios. Resources in the gas portfolio include gas supply arrangements, gas storage and gas transportation contracts. Resources in the electric portfolio include power purchase agreements, generating resources and transmission contracts.

The Company's energy risk management staff develops hedging strategies to manage deficit or surplus positions in the portfolios. The Company's energy risk policy states that hedging and optimization strategies will be consistent with Company objectives. The Company relies on risk analysis, operational factors, professional judgment of its employees and fundamental analysis. The Company will engage in transactions that reduce risks in its electric and gas portfolios, and optimize unused capacity where possible. Cost and reliability factors are considered in its hedging strategies. The Company's hedging activities are aimed at removing risks from the Company's electric and gas portfolios, giving important consideration to cost of hedges and lost opportunity in order to find a balance between price stability and least cost. The hedge strategies for the gas and electric portfolios incorporate risk analysis, operational factors and professional judgment of its employees as well as fundamental analysis. Programmatic hedge plans are developed to ensure disciplined hedging, and discretion is used in hedging within specific guidelines of the programmatic hedge plans approved by the Risk Management Committee. Most hedges can be implemented in ways that retain the

Company's ability to use its energy supply optimization opportunities. Some hedges are structured similarly to insurance instruments, where the Company pays an insurance premium to protect against certain extreme conditions.

Without jeopardizing the security of supply within its portfolio, the Company also engages in optimizing the portfolio. Optimization may take the form of utilizing excess capacity, shaping flexible resources to capture their highest value and utilizing transmission capacity through third party transactions. As a result, portions of the Company's energy portfolio are monetized through the use of forward price instruments which help reduce overall costs.

The Company has entered into master netting agreements with counterparties when available to mitigate credit exposure to those counterparties. The Company believes that entering into such agreements reduces risk of settlement default for the ability to make only one net payment. In addition, the Company believes risk is mitigated with an improved position in potential counterparty bankruptcy situations due to a consistent netting approach.

At December 31, 2004, the Company was subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

Transactions that qualify as hedge transactions under SFAS No. 133 are recorded on the balance sheet at fair value. Changes in fair value of the Company's derivatives are recorded each period in current earnings or other comprehensive income. Short-term derivative contracts for the purchase and sale of electricity are valued based on daily quoted prices from an independent energy brokerage service. Valuations for short-term and medium-term natural gas financial derivatives are derived from a combination of quotes from several independent energy brokers and are updated daily. Long-term gas financial derivatives are valued based on published pricing from a combination of independent brokerage services and are updated monthly. Option contracts are valued using market quotes and a Monte Carlo simulation based model approach.

At December 31, 2004, the Company had an after-tax net asset of approximately $20.0 million of energy contracts designated as qualifying cash flow hedges and a corresponding unrealized gain recorded in other comprehensive income. Of the amount in other comprehensive income, 99% of the mark-to-market gain beginning February 1, 2005 has been reclassified out of other comprehensive income to a deferred account in accordance with SFAS No. 71 due to the Company expecting to reach the $40 million cap under the PCA mechanism. The Company also had energy contracts that were marked-to-market at a gain of $1.2 million after-tax through current earnings for the 12 months ended December 31, 2004. These mark-to-market adjustments were primarily the result of excluding certain contracts from the normal purchase normal sale exception under SFAS No. 133. A portion of the mark-to-market adjustments beginning February 1, 2005, has been reclassified to a deferred account in accordance with SFAS No. 71 due to the Company expecting to reach the $40 million cap under the PCA mechanism. The Company also had a liability of approximately $12.1 million of gas contracts. All mark-to-market adjustments relating to the natural gas business have been reclassified to a deferred account in accordance with SFAS No. 71 due to the PGA mechanism. The PGA mechanism passes on to customers increases and decreases in the cost of natural gas supply. A hypothetical 10% increase in the market prices of natural gas and electricity would increase the fair value of qualifying cash flow hedges by approximately $5.5 million after-tax and would increase current earnings for those contracts marked-to-market in earnings by an immaterial amount.

Energy Derivative Contracts (Dollars in Millions)	Amounts
Fair value of contracts outstanding at December 31, 2003	$ 12.6
Contracts realized or otherwise settled during 2004	(9.8)
Changes in fair values of derivatives	6.9
Fair value of contracts outstanding at December 31, 2004	$ 9.7

Source of Fair Value (Dollars in Millions)	Fair Value of Contracts with Settlement During Year 2005	2006-2007	2008-2009	2010 And Thereafter	Total fair value
Prices actively quoted	$(3.8)	$ 6.3	$ --	$ --	$2.5
Prices provided by other external sources	--	5.4	1.8	--	7.2
Prices based on models and other valuation methods	$(3.8)	$11.7	$1.8	$ --	$9.7

Interest Rate Risk

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate notes and leases and 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 utilizes bank borrowings, commercial paper, line of credit facilities and accounts receivable securitization 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 or other financial hedge instruments to manage the interest rate risk associated with these debts. The Company did not have any swap instruments outstanding as of December 31, 2004 or 2003. The carrying amounts and the fair values of Puget Energy's debt instruments are:

(Dollars in Millions)	2004 Carrying Amount	2004 Fair Value	2003 Carrying Amount	2003 Fair Value
Financial liabilities:				
Short-term debt	$ 8.3	$ 8.3	$ 13.9	$ 13.9
Long-term debt – fixed-rate[1]	2,051.4	2,194.8	2,216.3	2,409.6
Long-term debt – variable-rate[1]	200.0	199.9	--	--

[1] *PSE's carrying value and fair value of both fixed-rate and variable-rate long-term debt in 2004 was $2,095.4 million and $2,238.7 million, respectively. PSE's carrying value and fair value of fixed-rate long-term debt in 2003 was $2,053.0 million and $2,250.4 million, respectively.*

In the third quarter 2004, the Company entered into two treasury lock contracts to hedge against potential rising interest rate exposure for a debt offering anticipated to be performed in the first half of 2005. A treasury lock is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a 30-year treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the treasury lock instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decrease related to the hedged debt from the date of issuance of the treasury lock instruments, the Company would pay the counterparty for the change in bond value. These treasury lock contracts were designated under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. All financial hedge contracts of this type are reviewed by senior management and presented to the Securities Pricing Committee of the Board of Directors, and are approved prior to execution. At December 31, 2004, the unrealized loss associated with the two treasury lock contracts was $11.3 million that qualify as cash flow hedges and is included in other comprehensive income. A hypothetical 10% decrease in the interest rate of a 30-year treasury note would result in an additional loss of $12.1 million net of tax in other comprehensive income. The treasury lock contracts will settle completely in 2005.

Treasury Lock Contracts (Dollars in Millions)	Amounts
Fair value of contracts outstanding at December 31, 2003	$ --
Contracts realized or otherwise settled during 2004	--
Changes in fair values of derivatives	(11.3)
Fair value of contracts outstanding at December 31, 2004	$ (11.3)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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 PSE'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 PSE.

REPORT OF MANAGEMENT AND STATEMENT OF RESPONSIBILITY

PUGET ENERGY, INC.
and
PUGET SOUND ENERGY, INC.

Puget Energy, Inc. and Puget Sound Energy, Inc. (the Company) management assumes accountability for maintaining compliance with our established financial accounting policies and for reporting our results with objectivity and integrity. The Company believes it is essential for investors and other users of the consolidated financial statements to have confidence that the financial information we provide is timely, complete, relevant, and accurate. Management is also responsible to present fairly Puget Energy's and Puget Sound Energy's consolidated financial statements, prepared in accordance with generally accepted accounting principles.

Management, with oversight of the Board of Directors, established and maintains a strong ethical climate under the guidance of our Corporate Ethics and Compliance Program so that our affairs are conducted to high standards of proper personal and corporate conduct. Management also established an internal control system that provides reasonable assurance as to the integrity and accuracy of the consolidated financial statements. These policies and practices reflect corporate governance initiatives that are compliant with the corporate governance requirements of the Sarbanes-Oxley Act of 2002, including:

- Our Board has adopted clear corporate governance guidelines.
- With the exception of the Chief Executive Officer, the Board members are independent of the Company and its management.
- All members of our key Board committees – the Audit Committee, the Compensation and Development Committee and the Governance and Public Affairs Committee – are independent of the Company and its management.
- The independent members of our Board meet regularly without the presence of Puget Energy and Puget Sound Energy management.
- The Charters of our Board committees clearly establish their respective roles and responsibilities.
- The Company has adopted a Compliance and Ethics Code with a hotline (through an independent third party) available to all employees, and our Audit Committee has procedures in place for the anonymous submission of employee complaints on accounting, internal accounting controls, or auditing matters. The Compliance Program is led by a senior officer of the Company.
- Our internal audit control function maintains critical oversight over the key areas of our business and financial processes and controls, and reports directly to our Board Audit Committee.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, reports directly to the Audit Committee of the Board of Directors. PricewaterhouseCoopers LLP's accompanying report on our consolidated financial statements is based on its examination conducted in accordance with auditing standards generally accepted in the United States, including a review of our internal control structure for purposes of designing their audit procedures. Our independent registered accounting firm has reported on the effectiveness of our internal control over financial reporting as required under Section 404 of the Sarbanes-Oxley Act of 2002. The Company is confident in the effectiveness of our internal controls and our ability to meet the requirements of this newly enacted legislation.

We are committed to improving shareholder value and accept our fiduciary oversight responsibilities. We are dedicated to ensuring that our high standards of financial accounting and reporting as well as our underlying system of internal controls are maintained. Our culture demands integrity and we have confidence in our processes, our internal controls, and our people, who are objective in their responsibilities and who operate under a high level of ethical standards.

/s/ Stephen P. Reynolds	/s/ Bertrand A. Valdman	/s/ James W. Eldredge
Stephen P. Reynolds	Bertrand A. Valdman	James W. Eldredge
President and Chief Executive Officer	*Senior Vice President Finance And Chief Financial Officer*	*Corporate Secretary and Chief Accounting Officer*

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Puget Energy, Inc.:

We have completed an integrated audit of Puget Energy, Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Puget Energy, Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index 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 financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements 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 provide a reasonable basis for our opinion.

As described in Note 2 to the consolidated financial statements, effective January 1, 2004, the Company changed its method of accounting for realized gains and losses on physically settled derivative contracts not held for trading purposes as required by EITF Issue No. 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03". As described in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations as required by Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations".

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Seattle, Washington
March 1, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Puget Sound Energy, Inc.:

We have completed an integrated audit of Puget Sound Energy, Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

<u>Consolidated financial statements and financial statement schedule</u>

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index 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 financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements 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 provide a reasonable basis for our opinion.

As described in Note 2 to the consolidated financial statements, effective January 1, 2004, the Company changed its method of accounting for realized gains and losses on physically settled derivative contracts not held for trading purposes as required by EITF Issue No. 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03". As described in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations as required by Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations".

<u>Internal control over financial reporting</u>

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Seattle, Washington
March 1, 2005

Puget Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2004	2003	2002
Operating revenues:			
Electric	$ 1,423,034	$ 1,400,743	$ 1,288,744
Gas	769,306	634,230	697,155
Non-utility construction services	369,936	341,787	319,529
Other	6,537	6,043	9,753
Total operating revenues	2,568,813	2,382,803	2,315,181
Operating expenses:			
Energy costs:			
Purchased electricity	723,567	714,469	568,230
Electric generation fuel	80,772	64,999	113,538
Residential exchange	(174,473)	(173,840)	(149,970)
Purchased gas	451,302	327,132	405,016
Unrealized (gain) loss on derivative instruments	(526)	106	(11,612)
Utility operations and maintenance	291,232	289,702	286,220
Other operations and maintenance	322,517	303,972	273,157
Depreciation and amortization	246,842	236,866	228,743
Conservation amortization	22,688	33,458	17,501
Goodwill impairment	91,196	--	--
Taxes other than income taxes	221,981	208,395	215,429
Income taxes	74,964	72,369	59,260
Total operating expenses	2,352,062	2,077,628	2,005,512
Operating income	216,751	305,175	309,669
Other income (deductions):			
Other income	4,292	1,564	5,458
Interest charges:			
AFUDC	5,420	3,343	1,969
Interest expense	(178,419)	(187,316)	(198,346)
Mandatorily redeemable securities interest expense	(91)	(1,072)	--
Preferred stock dividends of subsidiary	--	(5,151)	(7,831)
Minority interest in earnings of consolidated subsidiary	7,069	(177)	(867)
Net income before cumulative effect of accounting change	55,022	116,366	110,052
Cumulative effect of implementation of accounting change (net of tax)	--	169	--
Net income	$ 55,022	$ 116,197	$ 110,052
Common shares outstanding weighted average (in thousands)	99,470	94,750	88,372
Diluted shares outstanding weighted average (in thousands)	99,911	95,309	88,777
Basic earnings per common share before cumulative effect of accounting change	$ 0.55	$ 1.23	$ 1.24
Basic earnings per common share for cumulative effect of accounting change	--	--	--
Basic earnings per common share	$ 0.55	$ 1.23	$ 1.24
Diluted earnings per common share before cumulative effect of accounting change	$ 0.55	$ 1.22	$ 1.24
Diluted earnings per common share for cumulative effect of accounting change	--	--	--
Diluted earnings per common share	$ 0.55	$ 1.22	$ 1.24

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

Puget Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Utility plant:		
Electric plant	$ 4,389,882	$ 4,265,908
Gas plant	1,881,768	1,749,102
Common plant	409,677	390,622
Less: Accumulated depreciation and amortization	(2,452,969)	(2,325,405)
Net utility plant	4,228,358	4,080,227
Other property and investments:		
Goodwill, net	43,503	133,302
Intangibles, net	16,680	18,707
Other	257,785	250,084
Total other property and investments	317,968	402,093
Current assets:		
Cash	19,771	27,481
Restricted cash	1,633	2,537
Accounts receivable, net of allowance for doubtful accounts	216,304	227,115
Unbilled revenues	140,391	131,798
Purchased gas adjustment receivable	19,088	--
Materials and supplies, at average cost	107,356	85,128
Current portion of unrealized gain on derivative instruments	8,087	7,593
Prepayments and other	20,360	12,200
Total current assets	532,990	493,852
Other long-term assets:		
Regulatory asset for deferred income taxes	127,252	142,792
Regulatory asset for PURPA buyout costs	211,241	227,753
Unrealized gain on derivative instruments	13,765	8,624
Power cost adjustment mechanism	--	3,605
Other	401,795	340,056
Total other long-term assets	754,053	722,830
Total assets	$ 5,833,369	$ 5,699,002

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

Puget Energy Consolidated Balance Sheets

CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Capitalization:		
(See Consolidated Statements of Capitalization)		
Common equity	$ 1,622,276	$ 1,655,046
Total shareholders' equity	1,622,276	1,655,046
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250
Long-term debt	2,212,532	1,969,489
Total redeemable securities and long-term debt	2,494,671	2,251,628
Total capitalization	4,116,947	3,906,674
Minority interest in consolidated subsidiary	4,648	11,689
Current liabilities:		
Accounts payable	239,520	214,357
Short-term debt	8,297	13,893
Current maturities of long-term debt	38,933	246,829
Purchased gas adjustment liability	--	11,984
Accrued expenses:		
Taxes	77,698	77,451
Salaries and wages	13,829	12,712
Interest	29,005	32,954
Current portion of unrealized loss on derivative instruments	19,261	3,636
Tenaska disallowance reserve	3,156	--
Other	61,155	46,378
Total current liabilities	490,854	660,194
Long-term liabilities:		
Deferred income taxes	810,726	755,235
Long-term portion of unrealized loss on derivative instruments	249	--
Other deferred credits	409,945	365,210
Total long-term liabilities	1,220,920	1,120,445
Commitments and contingencies		
Total capitalization and liabilities	$ 5,833,369	$ 5,699,002

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

Puget Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Common equity:		
Common stock $0.01 par value, 250,000,000 shares authorized, 99,868,368 and 99,074,070 shares outstanding at December 31, 2004 and 2003	$ 999	$ 991
Additional paid-in capital	1,621,756	1,603,901
Earnings reinvested in the business	13,853	58,217
Accumulated other comprehensive income (loss) – net of tax	(14,332)	(8,063)
Total common equity	1,622,276	1,655,046
Preferred stock subject to mandatory redemption – cumulative – $100 par value: *		
4.84% series –150,000 shares authorized, 14,583 shares outstanding at December 31, 2004 and 2003	1,458	1,458
4.70% series –150,000 shares authorized, 4,311 shares outstanding at December 31, 2004 and 2003	431	431
Total preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250
Long-term debt:		
First mortgage bonds and senior notes	1,933,500	1,891,158
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Other notes	156,105	163,313
Unamortized discount – net of premium	--	(13)
Long-term debt due within one year	(38,933)	(246,829)
Total long-term debt excluding current maturities	2,212,532	1,969,489
Total capitalization	$ 4,116,947	$ 3,906,674

** Puget Energy has 50,000,000 shares authorized for $0.01 par value preferred stock. Puget Sound Energy has 13,000,000 shares authorized for $25 par value preferred stock and 3,000,000 shares authorized for $100 par value preferred stock. The preferred stock is available for issuance under mandatory and non-mandatory redemption provisions.*

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

Puget Energy Consolidated Statements of

COMMON SHAREHOLDERS' EQUITY

(Dollars in Thousands) For Years Ended December 31, 2004, 2003 & 2002	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
Balance at December 31, 2001	87,023,210	$ 870	$1,358,946	$ 32,229	$ (29,321)	$1,362,724
Net income	--	--	--	110,052	--	110,052
Common stock dividend declared	--	--	--	(105,687)	--	(105,687)
Common stock issued:						
New issuance	5,750,000	57	114,639	--	--	114,696
Dividend reinvestment plan	801,205	8	16,900	--	--	16,908
Employee plans	68,252	1	550	--	--	551
Other	(8)	--	(6,420)	(198)	--	(6,618)
Other comprehensive income	--	--	--	--	31,161	31,161
Balance at December 31, 2002	93,642,659	$ 936	$1,484,615	$ 36,396	$ 1,840	$1,523,787
Net income	--	--	--	116,197	--	116,197
Common stock dividend declared	--	--	--	(93,965)	--	(93,965)
Common stock issued:						
New issuance	4,650,600	47	102,231	--	--	102,278
Dividend reinvestment plan	721,340	7	15,447	--	--	15,454
Employee plans	59,475	1	1,616	--	--	1,617
Other	(4)	--	(8)	(411)	--	(419)
Other comprehensive loss	--	--	--	--	(9,903)	(9,903)
Balance at December 31, 2003	99,074,070	$ 991	$1,603,901	$ 58,217	$ (8,063)	$1,655,046
Net income	--	--	--	55,022	--	55,022
Common stock dividend declared	--	--	--	(99,386)	--	(99,386)
Common stock issued:						
New issuance	5,195	--	68	--	--	68
Dividend reinvestment plan	681,491	7	15,170	--	--	15,177
Employee plans	107,612	1	2,617	--	--	2,618
Other comprehensive loss	--	--	--	--	(6,269)	(6,269)
Balance at December 31, 2004	99,868,368	$ 999	$1,621,756	$ 13,853	$ (14,332)	$1,622,276

Puget Energy Consolidated Statements of

COMPREHENSIVE INCOME

(Dollars in Thousands) For Years Ended December 31	2004	2003	2002
Net income	$ 55,022	$ 116,197	$ 110,052
Other comprehensive income, net of tax:			
Unrealized holding losses on marketable securities during the period	--	(45)	(1,359)
Reclassification adjustment for realized gains on marketable securities included in net income	--	(1,518)	--
Foreign currency translation adjustment	275	80	63
Minimum pension liability adjustment	157	(1,122)	(2,098)
Unrealized gains on derivative instruments during the period	6,820	8,576	2,853
Reversal of unrealized (gains) losses on derivative instruments settled during the period	(10,418)	181	31,702
Deferral related to power cost adjustment mechanism	(3,103)	(16,055)	--
Other comprehensive income (loss)	(6,269)	(9,903)	31,161
Comprehensive income	$ 48,753	$ 106,294	$ 141,213

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

Puget Energy Consolidated Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2004	2003	2002
Operating activities:			
Net income	$ 55,022	$ 116,197	$ 110,052
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	246,842	236,866	228,743
Deferred income taxes and tax credits – net	72,702	57,470	151,318
Gain from sale of securities	--	(2,889)	--
Net unrealized (gains) losses on derivative instruments	(526)	106	(11,612)
Other (including conservation amortization)	10,103	18,683	(18,827)
Cash collateral received from (returned to) energy supplier	6,320	(21,425)	21,425
Increase (decrease) in residential exchange program	1,668	(25,989)	21,201
Goodwill impairment	91,196	--	--
Pension plan funding	--	(26,521)	--
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	2,218	37,769	46,860
Materials and supplies	(22,228)	(14,727)	22,088
Prepayments and other	(8,159)	(738)	141
Purchased gas receivable /liability	(31,073)	(71,826)	121,039
Accounts payable	25,163	6,464	34,351
Taxes payable	247	13,405	(18,260)
Tenaska disallowance reserve	3,156	--	--
Accrued expenses and other	3,709	(4,939)	(4,603)
Net cash provided by operating activities	456,360	317,906	703,916
Investing activities:			
Construction and capital expenditures – excluding equity AFUDC	(409,403)	(285,510)	(235,786)
Energy efficiency expenditures	(24,852)	(18,579)	(11,356)
Restricted cash	905	20,106	(18,871)
Cash received from sale of securities	--	3,161	--
Refundable cash received for customer construction projects	13,424	5,045	5,787
Investments by InfrastruX	--	(10,659)	(41,602)
Other	1,747	2,151	(15,761)
Net cash used by investing activities	(418,179)	(284,285)	(317,589)
Financing activities:			
Decrease in short-term debt – net	(5,596)	(33,402)	(301,281)
Dividends paid	(86,873)	(86,671)	(97,321)
Issuance of common stock	5,413	106,659	120,214
Issuance of bonds and notes	343,841	319,497	107,518
Redemption of preferred stock	--	(60,000)	--
Redemption of mandatorily redeemable preferred stock	--	(41,273)	(7,500)
Redemption of trust preferred stock	--	(19,750)	--
Redemption of bonds and notes	(308,708)	(357,510)	(119,281)
Other	6,032	(10,359)	(4,363)
Net cash used by financing activities	(45,891)	(182,809)	(302,014)
Increase (decrease) in cash from net income	(7,710)	(149,188)	84,313
Cash at beginning of year	27,481	176,669	92,356
Cash at end of year	$ 19,771	$ 27,481	$ 176,669
Supplemental Cash Flow Information:			
Cash payments for:			
Interest (net of capitalized interest)	$ 182,419	$ 192,845	$ 200,392
Income taxes (net refunds)	(1,232)	(2,777)	(81,652)

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

Puget Sound Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2004	2003	2002
Operating revenues:			
Electric	$ 1,423,034	$ 1,400,743	$ 1,288,744
Gas	769,306	634,230	697,155
Other	6,537	6,043	9,753
Total operating revenues	2,198,877	2,041,016	1,995,652
Operating expenses:			
Energy costs:			
Purchased electricity	723,567	714,469	568,230
Electric generation fuel	80,772	64,999	113,538
Residential exchange	(174,473)	(173,840)	(149,970)
Purchased gas	451,302	327,132	405,016
Unrealized (gain) loss on derivative instruments	(526)	106	(11,612)
Utility operations and maintenance	291,232	289,702	286,220
Other operations and maintenance	1,342	1,203	1,602
Depreciation and amortization	228,566	220,087	215,317
Conservation amortization	22,688	33,458	17,501
Taxes other than income taxes	208,989	194,857	202,381
Income taxes	77,177	70,939	52,836
Total operating expenses	1,910,636	1,743,112	1,701,059
Operating income	288,241	297,904	294,593
Other income (deductions):			
Other income	4,362	1,587	5,215
Interest charges:			
AFUDC	5,420	3,343	1,969
Interest expense	(171,740)	(181,707)	(192,829)
Mandatorily redeemable securities interest expense	(91)	(1,072)	--
Net income before cumulative effect of accounting change	126,192	120,055	108,948
Cumulative effect of implementation of accounting change (net of tax)	--	169	--
Net income	126,192	119,886	108,948
Less: preferred stock dividends accrual	--	5,151	7,831
Income for common stock	$ 126,192	$ 114,735	$ 101,117

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

Puget Sound Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Utility plant:		
Electric plant	$ 4,389,882	$ 4,265,908
Gas plant	1,881,768	1,749,102
Common plant	409,677	390,622
Less: Accumulated depreciation and amortization	(2,452,969)	(2,325,405)
Net utility plant	4,228,358	4,080,227
Other property and investments	157,670	160,280
Current assets:		
Cash	12,955	14,778
Restricted cash	1,633	2,537
Accounts receivable, net of allowance for doubtful accounts	138,792	155,649
Unbilled revenues	140,391	131,798
Purchased gas adjustment receivable	19,088	--
Materials and supplies, at average cost	97,578	77,206
Current portion of unrealized gain on derivative instruments	8,087	7,593
Prepayments and other	6,247	6,285
Total current assets	424,771	395,846
Other long-term assets:		
Regulatory asset for deferred income taxes	127,252	142,792
Regulatory asset for PURPA buyout costs	211,241	227,753
Unrealized gain on derivative instruments	13,765	8,624
Power cost adjustment mechanism	--	3,605
Other	401,030	339,977
Total other long-term assets	753,288	722,751
Total assets	$ 5,564,087	$ 5,359,104

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

Puget Sound Energy Consolidated Balance Sheets

CAPITALIZATION AND LIABILITIES

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Capitalization:		
(See Consolidated Statements of Capitalization):		
Common equity	$ 1,592,433	$ 1,555,469
Total shareholders' equity	1,592,433	1,555,469
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250
Long-term debt	2,064,360	1,950,347
Total redeemable securities and long-term debt	2,346,499	2,232,486
Total capitalization	3,938,932	3,787,955
Current liabilities:		
Accounts payable	229,747	206,465
Current maturities of long-term debt	31,000	102,658
Purchased gas adjustment liability	--	11,984
Accrued expenses:		
Taxes	81,634	82,342
Salaries and wages	13,829	12,712
Interest	29,005	32,954
Current portion of unrealized loss on derivative instruments	19,261	3,636
Tenaska disallowance reserve	3,156	--
Other	34,918	26,514
Total current liabilities	442,550	479,265
Long-term liabilities:		
Deferred income taxes	787,179	731,944
Long-term portion of unrealized loss on derivative instruments	249	--
Other deferred credits	395,177	359,940
Total long-term liabilities	1,182,605	1,091,884
Commitments and contingencies		
Total capitalization and liabilities	$ 5,564,087	$ 5,359,104

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

Puget Sound Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2004	2003
Common equity:		
Common stock ($10 stated value) – 150,000,000 shares authorized, 85,903,791 shares outstanding.	$ 859,038	$ 859,038
Additional paid-in capital	609,467	604,451
Earnings reinvested in the business	138,678	100,186
Accumulated other comprehensive income (loss) – net of tax	(14,750)	(8,206)
Total common equity	1,592,433	1,555,469
Preferred stock subject to mandatory redemption - cumulative $100 par value:*		
4.84% series – 150,000 shares authorized, 14,583 shares outstanding at December 31, 2004 and 2003	1,458	1,458
4.70% series – 150,000 shares authorized, 4,311 shares outstanding at December 31, 2004 and 2003	431	431
Total preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280,250	280,250
Long-term debt:		
First mortgage bonds and senior notes	1,933,500	1,891,158
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Unamortized discount – net of premium	--	(13)
Long-term debt due within one year	(31,000)	(102,658)
Total long-term debt excluding current maturities	2,064,360	1,950,347
Total capitalization	$ 3,938,932	$ 3,787,955

**13,000,000 shares authorized for $25 par value preferred stock and 3,000,000 shares authorized for $100 par value preferred stock, both of which are available for issuance under mandatory and non-mandatory redemption provisions.*

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

Puget Sound Energy Consolidated Statements of

COMMON SHAREHOLDERS' EQUITY

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31, 2004, 2003 & 2002	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
Balance at December 31, 2001	85,903,791	$859,038	$382,592	$ 55,345	$ (29,321)	$1,267,654
Net income	--	--	--	108,948	--	108,948
Preferred stock dividend declared	--	--	--	(7,904)	--	(7,904)
Common stock dividend declared	--	--	--	(89,418)	--	(89,418)
Investment received from Puget Energy	--	--	115,736	--	--	115,736
Other	--	--	7	--	--	7
Other comprehensive income	--	--	--	--	31,098	31,098
Balance at December 31, 2002	85,903,791	$859,038	$498,335	$ 66,971	$ 1,777	$1,426,121
Net income	--	--	--	119,886	--	119,886
Preferred stock dividend declared	--	--	--	(5,562)	--	(5,562)
Common stock dividend declared	--	--	--	(81,109)	--	(81,109)
Investment received from Puget Energy	--	--	106,124	--	--	106,124
Other	--	--	(8)	--	--	(8)
Other comprehensive loss	--	--	--	--	(9,983)	(9,983)
Balance at December 31, 2003	85,903,791	$859,038	$604,451	$100,186	$ (8,206)	$1,555,469
Net income	--	--	--	126,192	--	126,192
Common stock dividend declared	--	--	--	(87,700)	--	(87,700)
Investment received from Puget Energy	--	--	5,016	--	--	5,016
Other comprehensive loss	--	--	--	--	(6,544)	(6,544)
Balance at December 31, 2004	85,903,791	$859,038	$609,467	$138,678	$ (14,750)	$1,592,433

Puget Sound Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2004	2003	2002
Net income	$ 126,192	$ 119,886	$ 108,948
Other comprehensive income, net of tax:			
Unrealized holding losses on marketable securities during the period	--	(45)	(1,359)
Reclassification adjustment for realized gains on marketable securities included in net income	--	(1,518)	--
Minimum pension liability adjustment	157	(1,122)	(2,098)
Unrealized gains on derivative instruments during the period	6,820	8,576	2,853
Reversal of unrealized (gains) losses on derivative instruments settled during the period	(10,418)	181	31,702
Deferral related to power cost adjustment mechanism	(3,103)	(16,055)	--
Other comprehensive income (loss)	(6,544)	(9,983)	31,098
Comprehensive income	$ 119,648	$ 109,903	$ 140,046

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

Puget Sound Energy Consolidated Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2004	2003	2002
Operating activities:			
Net income	$ 126,192	$ 119,886	$ 108,948
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	228,566	220,087	215,317
Deferred federal income taxes and tax credits – net	72,446	49,276	140,536
Gain from sale of securities	--	(2,889)	--
Net unrealized (gain) loss on derivative instruments	(526)	106	(11,612)
Other (including conservation amortization)	20,806	14,591	(8,277)
Cash collateral received from (returned to) energy suppliers	6,320	(21,425)	21,425
Increase (decrease) in Residential Exchange Program	1,668	(25,989)	21,201
Pension plan funding	--	(26,521)	--
Change in certain current assets and current liabilities:			
Accounts receivable and unbilled revenue	8,264	33,370	61,539
Materials and supplies	(20,372)	(13,643)	21,755
Prepayments and other	38	2,622	(1,501)
Purchased gas receivable / liability	(31,073)	(71,826)	121,039
Accounts payable	23,282	12,863	38,893
Taxes payable	(707)	17,910	(13,646)
Tenaska disallowance reserve	3,156	--	--
Accrued expenses and other	(2,664)	(4,120)	277
Net cash provided by operating activities	435,396	304,298	715,894
Investing activities:			
Construction expenditures – excluding equity AFUDC	(393,891)	(269,973)	(224,165)
Energy efficiency expenditures	(24,852)	(18,579)	(11,356)
Restricted cash	905	20,106	(18,871)
Cash received from sale of securities	--	3,161	--
Refundable cash received for customer construction projects	13,424	5,045	5,787
Other	1,444	3,671	(14,472)
Net cash used by investing activities	(402,970)	(256,569)	(263,077)
Financing activities:			
Decrease in short-term debt – net	--	(30,340)	(307,828)
Dividends paid	(87,700)	(86,671)	(97,321)
Issuance of bonds and notes	200,000	304,465	40,000
Redemption of preferred stock	--	(60,000)	--
Redemption of mandatorily redeemable preferred stock	--	(41,273)	(7,500)
Redemption of trust preferred stock	--	(19,750)	--
Redemption of bonds and notes	(157,658)	(356,860)	(117,000)
Investment from Puget Energy	5,016	106,124	115,736
Other	6,093	(10,121)	(137)
Net cash used by financing activities	(34,249)	(194,426)	(374,050)
Increase (decrease) in cash from net income	(1,823)	(146,697)	78,767
Cash at beginning of year	14,778	161,475	82,708
Cash at end of year	$ 12,955	$ 14,778	$ 161,475
Supplemental Cash Flow Information:			
Cash payments for:			
Interest (net of capitalized interest)	$ 175,772	$ 187,256	$ 194,876
Income taxes (net refunds)	(1,042)	(1,456)	(81,973)

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

NOTES

To Consolidated Financial Statements of Puget Energy and Puget Sound Energy

NOTE 1. *Summary of Significant Accounting Policies*

BASIS OF PRESENTATION

Puget Energy is an exempt public utility holding company under the Public Utility Holding Company Act of 1935. Puget Energy owns Puget Sound Energy (PSE) and has a 90.9% ownership interest in InfrastruX Group, Inc. (InfrastruX). PSE is a public utility incorporated in the State of Washington and furnishes electric and gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. InfrastruX is a non-regulated construction service company incorporated in the State of Washington, which provides construction services to the electric and gas utility industries primarily in the Midwest, Texas, south-central and eastern United States regions.

The consolidated financial statements of Puget Energy include the accounts of Puget Energy and its subsidiaries, PSE and InfrastruX. Puget Energy holds all the common shares of PSE and holds a 90.9% interest in InfrastruX. The results of PSE and InfrastruX are presented on a consolidated basis. PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. Puget Energy and PSE are collectively referred to herein as "the Company." The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. Minority interests of InfrastruX's operating results are reflected in Puget Energy's consolidated financial statements. Certain amounts previously reported have been reclassified to conform with current year presentations with no effect on total equity or net income.

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 cost of additions to utility plant, including renewals and betterments, are capitalized at original cost. Costs include indirect costs such as engineering, supervision, certain taxes, 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 is charged to accumulated depreciation and costs associated with removal of property, less salvage, is charged to the cost of removal regulatory liability when the property is retired and removed from service.

NON-UTILITY PROPERTY, PLANT AND EQUIPMENT

The costs of other property, plant and equipment are stated at cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items is expensed, on a current basis. Gains and losses on assets sold or retired are reflected in earnings.

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS

The Company evaluates impairment of long-lived assets in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 establishes accounting standards for determining if long-lived assets are impaired and how losses, if any, should be recognized. The Company believes that the net cash flows are sufficient to cover the carrying value of its assets.

DEPRECIATION AND AMORTIZATION

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is comprised of software, small tools and office equipment. 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 2.9% in 2004, 2003 and 2002; depreciable gas utility plant was 3.4% in 2004, 3.5% in 2003 and 3.3% in 2002; and depreciable common utility plant was 4.6% in 2004, 4.7% in 2003 and 4.3% in 2002. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets.

CASH

All liquid investments with maturities of three months or less at the date of purchase are considered cash. The Company maintains cash deposits in excess of insured limits with certain financial institutions.

RESTRICTED CASH

Restricted cash represents cash to be used for specific purposes. The restricted cash balance was $1.6 million at December 31, 2004. Approximately $1.1 million in restricted cash represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. Approximately $0.4 million represents funds held for payment of principal and interest for conservation trust debt and approximately $0.1 million represents payments from the Bonneville Power Administration under the Residential and Farm Energy Exchange Benefit Credit program in excess of credits provided to customers.

MATERIAL AND SUPPLIES

Material and supplies consists primarily of materials and supplies used in the operation and maintenance of the electric and gas systems, coal, diesel and natural gas held for generation, and natural gas and liquefied natural gas held in storage for future sales. These items are recorded at the lower of cost or market value, primarily using the weighted average cost method.

REGULATORY ASSETS AND LIABILITIES

The Company accounts for its regulated operations in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS 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 SFAS 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.

The Company is allowed a return on the net regulatory assets and liabilities of 8.75% for electric rates beginning July 1, 2002 and gas rates beginning September 1, 2002. The 2001 allowed rate of return was 8.94% for electric rates and 9.15% for gas rates. The net regulatory assets and liabilities at December 31, 2004 and 2003 included the following:

(DOLLARS IN MILLIONS)	REMAINING AMORTIZATION PERIOD	2004	2003
PURPA electric energy supply contract buyout costs	4 to 7 years	$ 211.2	$ 227.8
Deferred income taxes	***	127.3	142.8
White River relicensing and other costs	*	65.3	20.8
Investment in Bonneville Exchange Power contract	12 years	44.1	47.6
Environmental remediation	*	42.3	41.6
Deferred AFUDC	30 years	30.4	30.3
Tree watch costs	10 years	28.3	29.0
Storm damage costs – electric	3.5 years	21.1	26.0
Purchased Gas Adjustment (PGA) receivable	*	19.1	--
Colstrip common property	19 years	13.9	14.6
PGA deferral of unrealized losses on derivative instruments	***	12.1	3.3
Various other regulatory assets	1 to 26 years	30.2	23.1
Power Cost Adjustment (PCA) mechanism	*	--	3.6
Cost of removal	**	(132.4)	(124.9)
PCA deferral of unrealized gain on derivative instrument	*	(30.8)	(24.3)
Gas Supply contract settlement	3.5 year	(10.1)	--
Deferred gains on property sales	3 years	(4.5)	(10.1)
Tenaska disallowance reserve	1 year	(3.2)	--
Purchased Gas Adjustment payable	***	--	(12.0)
Various other regulatory liabilities	1 to 22 years	(4.7)	(5.4)
Net regulatory assets and liabilities		$ 459.6	$ 433.8

* *Amortization period to be determined.*
** *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*
*** *Amortization period varies depending on timing of underlying transactions.*

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

In accordance with guidance provided by the Securities and Exchange Commission, the Company reclassified from accumulated depreciation to a regulatory liability $132.4 million and $124.9 million in 2004 and 2003, respectively, for cost of removal for utility plant. These amounts are collected from PSE's customers through depreciation rates.

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 8.76% beginning September 1, 2002 and 9.15% in 2001. The allowed AFUDC rate on electric utility plant was 8.76% beginning July 1, 2002 and 8.94% in 2001. To the extent amounts calculated using this rate exceed the AFUDC calculated rate 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 $1.4 million for 2004, $1.6 million for 2003 and $2.6 million for 2002. The deferred asset is being amortized over the average useful life of the Company's non-project utility plant.

Other Comprehensive Income

Items present in the Consolidated Statements of Comprehensive Income for Puget Energy and PSE are presented net of applicable tax at a 35% statutory rate.

Revenue Recognition

Operating utility revenues are recorded on the basis of service rendered, which includes estimated unbilled revenue. Sales to other utilities are recorded on a net service rendered basis in accordance with Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) Issue No. 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03." Non-utility subsidiaries recognize revenue when services are performed, upon the sale of assets or on a percent of completion basis for fixed priced contracts.

Allowance for Doubtful Accounts

An allowance for doubtful accounts is provided for energy customer accounts based upon a historical experience rate of write-offs of energy accounts receivable as compared to operating revenues. The allowance account is adjusted monthly for this experience rate. Energy accounts are considered past due 15 business days after the billing cycle. Once an account is past due, a 1% late payment fee is accrued per month for each month an account is past due. When an account is past due, the Company may assist the customer with the use of special payment arrangements. If no payment arrangements are made or if no contact is made from the customer, the Company has the option of stopping service. Once service is stopped or the customer leaves the service area, a final bill is mailed. Energy accounts are deemed uncollectible 74 business days after the final bill due date and are written off against the allowance account. The late payment fee continues to be accrued on past due accounts until they are written off.

Other non-energy receivable balances are reserved for in the allowance account based on facts and circumstances surrounding the receivable indicating some or all of the balance is uncollectible. Once exhaustive efforts have been made to collect these other receivables, the allowance account and corresponding receivable balance are written off.

The Company has provided for a $41.5 million reserve for fiscal 2000 sales transactions related to the California Independent System Operator and counterparties based upon probability of collection.

Puget Energy's allowance for doubtful accounts for 2004 and 2003 was $46.0 million and $45.8 million, respectively. PSE's allowance for doubtful accounts for 2004 and 2003 was $44.2 million and $44.0 million, respectively

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, workers' compensation claims and catastrophic property losses other than storm related. With approval of the Washington Commission, PSE is able to defer for collection in future rates certain uninsured storm damage costs associated with major storms.

Federal Income Taxes

The Company normalizes, with the approval of the Washington Commission, certain income tax items. Deferred taxes have been determined under SFAS 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 12).

Energy Efficiency

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 efficiency expenditures through a tariff rider mechanism. The rider mechanism allows the Company to defer the efficiency expenditures and amortize them to expense as PSE concurrently collects the efficiency expenditures in rates over a one-year period. As a result of the rider mechanism, electric energy efficiency expenditures have no impact on earnings.

Since 1995, the Company has been authorized by the Washington Commission to defer gas energy efficiency expenditures and recover them through a tariff tracker mechanism. The tracker mechanism allows the Company to defer efficiency 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 on any outstanding balance that is not being recovered in rates. As a result of the tracker mechanism, gas energy efficiency expenditures have no impact on earnings.

Energy efficiency programs reduce customer consumption of energy thus impacting energy margins. The impact of load reductions are adjusted in rates at each general rate case.

RATE ADJUSTMENT MECHANISMS

The Company has a power cost adjustment (PCA) mechanism that provides for an automatic rate adjustment if PSE's costs to provide customers' electricity falls outside certain bands from a normalized level of power costs established in the electric general rate case. The Company's cumulative maximum pre-tax earnings exposure due to power cost variations over the four-year period ending June 30, 2006 is limited to $40 million plus 1% of the excess. All significant variable power supply cost drivers are included in the PCA mechanism (hydroelectric generation variability, market price variability for purchased power and surplus power sales, natural gas and coal fuel price variability, generation unit forced outage risk and wheeling cost variability). The PCA mechanism apportions increases or decreases in power costs, on a graduated scale, between PSE and its customers. Any unrealized gains and losses from derivative instruments accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," are deferred in proportion to the cost-sharing arrangement under the PCA mechanism once the Company reaches its cap of $40 million.

The graduated scale is as follows:

ANNUAL POWER COST VARIABILITY	CUSTOMERS' SHARE	COMPANY'S SHARE[1]
+/- $20 million	0%	100%
+/- $20 million - $40 million	50%	50%
+/- $40 million - $120 million	90%	10%
+/- $120+ million	95%	5%

1 *Over the four-year period July 1, 2002 through June 30, 2006 the Company's share of pre-tax cost variation is capped at a cumulative $40 million plus 1% of the excess. Power cost variation after June 30, 2006 will be apportioned on an annual basis, based on the graduated scale.*

The differences between the actual cost of PSE's gas supplies and gas transportation contracts and that currently allowed by the Washington Commission are deferred and recovered or repaid through the purchased gas adjustment (PGA) mechanism. The PGA mechanism allows PSE to recover expected gas costs, and defer, as a receivable or liability, any gas costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including interest.

NATURAL GAS OFF-SYSTEM SALES AND CAPACITY RELEASE

The Company contracts for firm gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, however, the Company holds contractual rights to gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year there is excess capacity available for third-party gas sales, exchanges and capacity releases. The Company sells excess gas supplies, enters into gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate gas pipeline capacity and gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core gas customers. The proceeds from such activities, net of transactional costs, 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 nets the sales revenue and associated cost of sales for these transactions in purchased gas.

ENERGY RISK MANAGEMENT

The Company serves its regulated electric customers with an electric portfolio of owned and contracted resources. As a result, the portfolio exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company also serves its regulated gas customers with a gas portfolio of contracted resources which exposes the Company's customers to commodity price risks in the PGA mechanism. The Company's energy risk management function monitors and manages these risks using analytical models and tools. In addition, the Audit Committee of the Company's Board of Directors periodically assesses risk management policies.

The Company manages its energy supply portfolio to achieve three primary objectives:

- ensure that physical energy supplies are available to serve retail customer requirements;
- manage portfolio risks to limit undesired impacts on the Company's costs; and
- maximize the value of the Company's energy supply assets.

ACCOUNTING FOR DERIVATIVES

The Company follows the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, which requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. Certain contracts that would otherwise be considered derivatives are exempt from SFAS No. 133 if they qualify for a normal purchase normal sale exception. The Company enters into both physical and financial contracts to manage its energy resource portfolio. The majority of these contracts qualify for the normal purchase normal sale exception. However, those contracts that do not meet normal purchase or normal sale exception are derivatives and, pursuant to SFAS No. 133, are reported at their fair value in the balance sheet. Changes in their fair value are reported in earnings unless they meet specific hedge accounting criteria, in which case changes in their fair market value are recorded in comprehensive income until the time the transaction that they are hedging is recorded as income. The Company designates a derivative instrument as a qualifying cash flow hedge if the change in the fair value of the derivative is highly effective at offsetting the changes in the fair value of an asset, a liability or a forecasted transaction. To the extent that a portion of a derivative designated as a hedge is ineffective, changes in the fair value of the ineffective portion of that derivative are recognized currently in earnings. Changes in the market value of derivative transactions related to obtaining gas for the Company's retail gas business are deferred as regulatory assets or liabilities as a result of the Company's PGA mechanism and recorded in earnings as the transactions are executed. In addition, once the Company reaches the $40 million PCA cap, any unrealized gains or losses are deferred in proportion to the cost-sharing arrangement under the PCA.

STOCK-BASED COMPENSATION

The Company has various stock-based compensation plans which, prior to 2003, were accounted for according to APB No. 25, "Accounting for Stock Issued to Employees," and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation." In 2003, the Company adopted the fair value based accounting of SFAS No. 123 using the prospective method under the guidance of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company applies SFAS No. 123 accounting to stock compensation awards granted from 2003 on, while grants that were made in years prior to 2003 are accounted for using the intrinsic value method of APB No. 25. Had the Company used the fair value method of accounting specified by SFAS No. 123 for all grants at their grant date rather than prospectively implementing SFAS No. 123, net income and earnings per share would have been as follows:

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS) YEARS ENDED DECEMBER 31	2004	2003	2002
Net income, as reported	$ 55,022	$ 116,197	$ 110,052
Add: Total stock-based employee compensation expense included in net income, net of tax	2,641	4,180	4,103
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(3,303)	(3,314)	(3,495)
Pro forma net income	$ 54,360	$ 117,063	$ 110,660
Earnings per common share:			
Basic as reported	$ 0.55	$ 1.23	$ 1.24
Diluted as reported	$ 0.55	$ 1.22	$ 1.24
Basic pro forma	$ 0.55	$ 1.24	$ 1.25
Diluted pro forma	$ 0.54	$ 1.23	$ 1.25

DEBT RELATED COSTS

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment. At times the Company will enter into treasury lock transactions to hedge against the potential rising interest rates. The transaction, when settled, will be amortized over the related debt issuance life.

GOODWILL AND INTANGIBLES (PUGET ENERGY ONLY)

On January 1, 2002, SFAS No. 142, "Goodwill and Other Intangible Assets," became effective and as a result Puget Energy ceased amortization of goodwill. Puget Energy performed an initial impairment review of goodwill and an annual impairment review thereafter. The initial review was completed during the first half of 2002, which did not result in an impairment charge. Goodwill is reviewed annually to determine if any impairment exists. If goodwill is determined to have an impairment, Puget Energy would record in the period of determination an impairment charge to earnings. Intangibles with finite lives are amortized based on the expected pattern of use or on a straight-line basis over the expected periods to be benefited. The goodwill and intangibles recorded on the balance sheet of Puget Energy are the result of several acquisitions of companies by InfrastruX.

In 2004, InfrastruX recorded a $91.2 million ($76.6 million after tax and minority interest) impairment charge related to goodwill from acquired companies. See Note 18.

EARNINGS PER COMMON SHARE (PUGET ENERGY ONLY)

Basic earnings per common share has been computed based on weighted average common shares outstanding of 99,470,000, 94,750,000 and 88,372,000 for 2004, 2003 and 2002, respectively. Diluted earnings per common share has been computed based on weighted average common shares outstanding of 99,911,000, 95,309,000 and 88,777,000 for 2004, 2003 and 2002, respectively, which includes the dilutive effect of securities related to employee stock-based compensation plans.

ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

Rainier Receivables, Inc. is a wholly owned, bankruptcy-remote subsidiary of PSE formed in December 2002 for the purpose of purchasing customers' accounts receivable, both billed and unbilled, of PSE. Rainier Receivables and PSE have an agreement whereby Rainier Receivables can sell, on a revolving basis, up to $150 million of those eligible receivables. The current agreement expires in December 2005. Rainier Receivables is obligated to pay fees that approximate the third-party purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. At December 31, 2004, Rainier Receivables had sold $150 million of receivables compared to $111 million of receivables sold at December 31, 2003.

NOTE 2. *New Accounting Pronouncements*

In December 2004, FASB issued SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), which revises SFAS No. 123, "Accounting For Stock-Based Compensation." SFAS No. 123R requires companies that issue share-based payment awards to employees for goods or services to recognize as compensation expense, the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS No. 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair-value method of accounting at the time of their award. SFAS No. 123R is effective for reporting periods beginning after June 15, 2005. The Company is currently evaluating what impact the application of SFAS No. 123R will have on its operations. The Company had adopted the fair value provisions of SFAS No. 123 "Accounting for Stock Based Compensation" in January 2003.

In December 2004, FASB issued FASB Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" (FSP No. 109-1). FSP No. 109-1 states that the staff position related to deductions as a result of the American Jobs Creation Act (the Act) should be treated as a "special deduction", as described in SFAS No. 109, "Accounting For Income Taxes" and therefore has no effect on deferred tax assets or liabilities existing at the enactment date. The Company is currently evaluating the impact of FSP No. 109-1 (which was effective upon issuance) and any deduction available under the Act. Any deduction available, if determined, is applicable to the Company's 2005 tax year.

On May 19, 2004, FASB issued FASB Staff Position (FSP) No. 106-2 "Accounting and Disclosure Requirements Related to Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare Prescription Drug and Modernization Act which was signed into law in December 2003. The law provides a subsidy for plan sponsors that provide prescription drug benefits to Medicare beneficiaries that are equivalent to the Medicare Part D plan. Based upon an actuarial assessment, PSE will not be eligible for such subsidies, thus FSP No. 106-2 will have no impact on PSE's retiree medical plans.

The Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) at its July 2003 meeting came to a consensus concerning EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03." The consensus reached was that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes are reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Based on the guidance by EITF No. 03-11, the Company determined that its non-trading derivative instruments should be reported net and implemented this treatment effective January 1, 2004. As a result of the implementation, Electric Revenue and Purchased Electricity Expense both decreased $108.7 million in 2003 and $77.1 million in 2002, respectively, with no impact on financial position or net income.

In March 2004, the EITF came to a consensus concerning EITF Issue No. 03-16, "Accounting for Investments in Limited Liability Companies." The consensus reached was that an investment in a limited liability company (LLC) should be accounted for using the equity method for investments greater than 3% to 5%. The adoption of EITF No. 03-16 is effective for reporting periods beginning after June 15, 2004, with any adjustments being accounted for as a cumulative effect of a change in accounting principle. The Company reviewed its investments and determined one investment held by PSE met the criteria established in EITF No. 03-16.

In May 2003, FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 establishes the requirements for classifying and measuring as liabilities certain financial instruments that embody obligations to redeem the financial instruments by the issuer. The adoption of SFAS No. 150 is effective with the first fiscal year or interim period beginning after June 15, 2003. However, on November 5, 2003 FASB deferred for an indefinite period certain mandatorily redeemable noncontrolling interests associated with finite-lived subsidiaries. The Company does not have any noncontrolling interest in finite-lived subsidiaries and therefore, is not affected by the deferral. Prior periods will not be restated for the new presentation.

SFAS No. 150 requires the Company to classify its mandatorily redeemable preferred stock as liabilities. As a result, the corresponding dividends on the mandatorily redeemable preferred stock are classified as interest expense on the income statement with no impact on income for common stock.

In January 2003, FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46), as further revised in December 2003 with FIN 46R, which clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have a controlling interest or sufficient equity at risk for the entity to finance its activities without additional financial support. FIN 46 requires that if a business entity has a controlling financial interest in a variable interest entity, the financial statements must be included in the consolidated financial statements of the business entity. The adoption of FIN 46 for all interests in variable interest entities created after January 31, 2003 was effective immediately. For variable interest entities created before February 1, 2003, it was effective July 1, 2003. The adoption of FIN 46R was effective March 31, 2004. The Company evaluated its contractual arrangements and determined PSE's 1995 conservation trust off-balance sheet financing transaction met this guidance, and therefore it was consolidated in the third quarter 2003. As a result, electricity revenues for 2003 increased $5.7 million, while conservation amortization and interest expense increased by the corresponding amount with no impact on earnings. FIN 46R also impacted the treatment of the Company's mandatorily redeemable preferred securities of a wholly owned subsidiary trust holding solely junior subordinated debentures of the corporation (trust preferred securities). Previously, these trust-preferred securities were consolidated into the Company's operations. As a result of FIN 46R, these securities have been deconsolidated and were classified as junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities (junior subordinated debt) in the fourth quarter 2003. This change had no impact on the Company's results of operations. The Company also evaluated its purchase power agreements and determined that three counterparties may be considered variable interest entities. As a result, PSE submitted requests for information to those parties; however, the parties have refused to submit to PSE the necessary information for PSE to determine whether they meet the requirements of a variable interest entity. PSE also determined that it does not have a contractual right to such information. PSE will continue to submit requests for information to the counterparties in the future to determine if FIN 46R is applicable.

For the three purchase power agreements that may be considered variable interest entities under FIN 46R, PSE is required to buy all the generation from these plants, subject to displacement by PSE, at rates set forth in the purchase power agreements. If at any time the counterparties cannot deliver energy to PSE, PSE would have to buy energy in the wholesale market at prices which could be higher or lower than the purchase power agreement prices. PSE's Purchased Electricity expense for 2004 and 2003 for these three entities was $251.2 million and $273.9 million, respectively.

In June 2001, FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," (SFAS No. 143) which is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company adopted the new rules on asset retirement obligations on January 1, 2003. As a result, the Company recorded a $0.2 million charge to income for the cumulative effect of this accounting change. (See Note 3.)

In November 2004, FASB reached a decision concerning a proposed interpretation of SFAS No. 143 titled "Accounting for Conditional Asset Retirement Obligations." The proposed interpretation addresses the issue of whether SFAS No. 143 requires an entity to recognize a liability for a legal obligation to perform asset retirement when the asset retirement activities are conditional on a future event, and if so, the timing and valuation of the recognition. The decision reached by FASB was that there are no instances where a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation. This, if part of the final issued interpretation, could potentially have an impact on the Company as assets that were previously considered outside the scope of SFAS No. 143 may be subject to the terms of the proposed interpretation. FASB indicated that the final interpretation is anticipated to be issued in the first quarter 2005, with an effective date for fiscal years ending after December 15, 2005, with any adjustment accounted for as a cumulative effect of an accounting change. The Company is currently evaluating what impact this proposed interpretation may have on the Company if issued.

NOTE 3. *Utility and Non-Utility Plant*

UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	ESTIMATED USEFUL LIFE (YEARS)	2004	2003
Electric, gas and common utility plant classified by prescribed accounts at original cost:			
Distribution plant	10-60	$ 4,219,720	$ 4,030,570
Production plant	40-100	1,150,781	1,144,354
Transmission plant	30-95	426,543	379,889
General plant	10-35	346,472	344,781
Construction work in progress	NA	129,966	121,622
Intangible plant (including capitalized software)	3-29	283,179	270,235
Plant acquisition adjustment	21	76,623	76,623
Underground storage	50-80	23,089	22,362
Liquefied natural gas storage	14-50	12,345	2,348
Plant held for future use	--	7,296	7,608
Other	27-34	5,313	5,240
Less accumulated provision for depreciation		(2,452,969)	(2,325,405)
Net utility plant		$ 4,228,358	$ 4,080,227

NON-UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	ESTIMATED USEFUL LIFE (YEARS)	2004	2003
Non-utility plant	3-20	$ 138,656	$ 122,926
Intangibles	5-20	24,056	23,985
Less accumulated depreciation and amortization		(52,947)	(36,272)
Net non-utility plant and intangibles		$ 109,765	$ 110,639

Non-utility plant is composed primarily of the property, plant and equipment of InfrastruX. Non-utility plant and accumulated depreciation is included in "other" under "other property and investments" in the Puget Energy balance sheet. Intangibles are composed of patents, contractual customer relationships and other amortizable intangible assets of InfrastruX.

On January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The Company recorded an after-tax charge to income of $0.2 million in the first quarter 2003 for the cumulative effect of the accounting change. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

The Company identified various asset retirement obligations at January 1, 2003, which were included in the cumulative effect of the accounting change. The Company has an obligation (1) to dismantle two leased electric generation turbine units and deliver the turbines to the nearest railhead at the termination of the lease in 2009; (2) to remove certain structures as a result of renegotiations with the Department of Natural Resources of a now-expired lease; (3) to replace or line all cast iron pipes in its service territory by 2007 as a result of a 1992 Washington Commission order; and (4) to restore ash holding ponds at a jointly owned coal-fired electric generating facility in Montana.

The following table describes all changes to the Company's asset retirement obligation liability:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2004	2003
Asset retirement obligation at beginning of year	$ 3,421	$ --
Liability recognized in transition	--	3,592
Liability settled in the period	--	(261)
Accretion expense	95	90
Asset retirement obligation at December 31	$ 3,516	$ 3,421

The pro forma asset retirement obligation liability balances as if SFAS No. 143 had been adopted on January 1, 2002 (rather than January 1, 2003) are as follows:

(DOLLARS IN THOUSANDS)	
Pro forma amounts of liability for asset retirement obligation at January 1, 2002	$ 3,497
Pro forma amounts of liability for asset retirement obligation at December 31, 2002	3,592

The pro forma income statement effect as if SFAS No. 143 had been adopted on January 1, 2002 (rather than January 1, 2003) is as follows:

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	2003	2002
Net income, as reported	$ 116,197	$ 110,052
Add: SFAS No. 143 transition adjustment, net of tax	169	--
Less: Pro forma accretion expense, net of tax	--	(62)
Pro forma net income	$ 116,366	$ 109,990
Earnings per share:		
Basic as reported	$ 1.23	$ 1.24
Diluted as reported	$ 1.22	$ 1.24
Basic pro forma	$ 1.23	$ 1.24
Diluted pro forma	$ 1.22	$ 1.24

NOTE 4. *Preferred Stock*

On November 1, 2003, all the authorized and outstanding 2.4 million shares of the $25 par value 7.45% Series preferred stock not subject to mandatory redemption were redeemed at par value plus accrued dividends. There were no other redemptions or reacquired shares of this preferred stock series in 2003.

NOTE 5. *Preferred Share Purchase Right*

On October 23, 2000, the Board of Directors declared a dividend of one preferred share purchase right (a Right) for each outstanding common share of Puget Energy. The dividend was paid on December 29, 2000 to shareholders of record on that date. The Rights will become exercisable only if a person or group acquires 10% or more of Puget Energy's outstanding common stock or announces a tender offer which, if consummated, would result in ownership by a person or group of 10% or more of the outstanding common stock. Each Right will entitle the holder to purchase from Puget Energy one one-hundredth of a share of preferred stock with economic terms similar to that of one share of Puget Energy's common stock at a purchase price of $65, subject to adjustments. The Rights expire on December 21, 2010, unless redeemed or exchanged earlier by Puget Energy.

NOTE 6. *Dividend Restrictions*

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 of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $274.4 million at December 31, 2004. For the years 2004, 2003 and 2002, the aggregate dividends declared per share were $1.00, $1.00 and $1.21, respectively.

Under the general rate settlement, PSE must rebuild its common equity ratio to at least 39%, with milestones of 35% and 39% at the end of 2004 and 2005, respectively. If PSE should fail to meet the schedule, it would be subject to a 2% rate reduction penalty. The common equity ratio for PSE at December 31, 2004 was 40.1%.

NOTE 7. *Redeemable Securities*

	Preferred Stock Subject to Mandatory Redemption $100 Par Value		
	4.70% Series	4.84% Series	7.75% Series
Shares outstanding December 31, 2001	4,311	14,808	487,500
Acquired for sinking fund:			
2002	--	--	(75,000)
2003	--	--	(75,000)
2004	--	--	--
Called for redemption or reacquired and canceled:			
2002	--	--	--
2003	--	(225)	(337,500)
2004	--	--	--
Shares outstanding December 31, 2004	4,311	14,583	--

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

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: 4.70% Series and 4.84% Series, 3,000 shares each. All previous sinking fund requirements have been satisfied. The $100 par value 7.75% Series preferred stock subject to mandatory redemption was fully redeemed at $102.07 per share plus accrued dividends on August 15, 2003. At December 31, 2004, there were 34,689 shares of the 4.70% Series and 18,192 shares of the 4.84% 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: 4.70% Series, $101.00 and 4.84% Series, $102.00.

JUNIOR SUBORDINATED DEBENTURES OF THE CORPORATION PAYABLE TO A SUBSIDIARY TRUST HOLDING MANDATORILY REDEEMABLE PREFERRED SECURITIES

In 1997 and 2001, the Company formed Puget Sound Energy Capital Trust I and Puget Sound Energy Capital Trust II, respectively, 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 Trusts and the Company owns all common securities of the Trusts.

The Debentures of Trust I and Trust II have an interest rate of 8.231% and 8.40%, respectively, and a stated maturity date of June 1, 2027 and June 30, 2041, respectively. The Trust Securities are subject to mandatory redemption at par on the stated maturity date of the Debentures. The Trust Securities in the Capital Trust I may be redeemed earlier, under certain conditions, at the option of the Company. The Capital Trust II Securities may be redeemed at any time on or after June 30, 2006 at par, under certain conditions, at the option of the Company. Dividends relating to preferred securities are included in interest expense for all periods presented.

NOTE 8. *Long-Term Debt*

FIRST MORTGAGE BONDS AND SENIOR NOTES
AT DECEMBER 31 (DOLLARS IN THOUSANDS)

SERIES	DUE	2004	2003	SERIES	DUE	2004	2003
6.07%	2004	$ --	$10,000	6.46%	2009	150,000	150,000
6.10%	2004	--	8,500	6.61%	2009	3,000	3,000
7.70%	2004	--	50,000	6.62%	2009	5,000	5,000
7.80%	2004	--	30,000	7.12%	2010	7,000	7,000
6.92%	2005	11,000	11,000	7.96%	2010	225,000	225,000
6.93%	2005	20,000	20,000	7.69%	2011	260,000	260,000
Variable	2006	200,000	--	6.83%	2013	3,000	3,000
6.58%	2006	10,000	10,000	6.90%	2013	10,000	10,000
8.06%	2006	46,000	46,000	7.35%	2015	10,000	10,000
8.14%	2006	25,000	25,000	7.36%	2015	2,000	2,000
7.02%	2007	20,000	20,000	6.74%	2018	200,000	200,000
7.04%	2007	5,000	5,000	9.57%	2020	25,000	25,000
7.75%	2007	100,000	100,000	7.35%	2024	--	55,000
3.363%	2008	150,000	150,000	7.15%	2025	15,000	15,000
6.51%	2008	1,000	1,000	7.20%	2025	2,000	2,000
6.53%	2008	3,500	3,500	7.02%	2027	300,000	300,000
7.61%	2008	25,000	25,000	7.00%	2029	100,000	100,000
					Total	$1,933,500	$1,887,000

In January 2004, 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 of any combination of common stock of Puget Energy and principal amount of senior notes secured by a pledge of first mortgage bonds. In July 2004, PSE issued $200 million in floating rate senior notes under its existing $500 million registration statement. The notes have a floating interest rate which is based on the three-month LIBOR rate plus 0.30% (2.37% at December 31, 2004), and mature in July 2006. The Company called and paid off five series of first mortgage bonds in 2004, totaling $153.5 million. The Company repaid the bonds using both cash on hand and proceeds from the $200 million floating rate senior notes.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE's earnings available for interest must be at least twice the annual interest charges on outstanding first mortgage bonds. At December 31, 2004, the earnings available for interest exceeded the required amount.

POLLUTION CONTROL BONDS

The Company has outstanding two series of Pollution Control Bonds. On February 19, 2003, the Board of Directors approved the refinancing of all Pollution Control Bonds series, which were issued in March 2003. 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 & 4.

Each series of bonds is collateralized by a pledge of PSE'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.

AT DECEMBER 31 (DOLLARS IN THOUSANDS) SERIES	DUE	2004	2003
2003A Series – 5.00%	2031	$ 138,460	$ 138,460
2003B Series – 5.10%	2031	23,400	23,400
Total		$ 161,860	$ 161,860

CONSERVATION TRUST FINANCINGS

In October 2004, the 6.45% Conservation Trust Bonds matured. PSE originally consolidated the 1995 Conservation Trust Bonds when FIN 46 went into effect in July 2003. The balance at December 31, 2003 was $4.2 million.

LONG-TERM REVOLVING CREDIT FACILITY (PUGET ENERGY ONLY)

Puget Energy has a $15.0 million revolving credit facility available through a bank. At December 31, 2004, there was $5.0 million outstanding at a weighted average interest rate of 3.07%, leaving $10.0 million available under the facility. On February 1, 2005, Puget Energy reduced the borrowing capacity under this credit facility to $5.0 million.

InfrastruX and its subsidiaries have signed credit agreements with several banks for up to $186.7 million, which expire at various dates from 2005 to 2007. Under the InfrastruX credit agreement, Puget Energy is the guarantor of $150.0 million of the line of credit. InfrastruX has borrowed $143.1 million at a weighted average interest rate of 2.96%, leaving a balance of $43.6 million available under the lines of credit at December 31, 2004. InfrastruX also has $18.4 million in equipment financing agreements with various vendors. These agreements mature at various dates from 2005 to 2009 and carry interest rates up to 7.45%.

LONG-TERM DEBT MATURITIES

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2005	2006	2007	2008	2009	THEREAFTER
Maturities of:						
Long-term debt	$ 38,933	$ 292,276	$ 259,866	$ 181,089	$ 158,441	$ 1,320,860

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2005	2006	2007	2008	2009	THEREAFTER
Maturities of:						
Long-term debt	$ 31,000	$ 281,000	$ 125,000	$ 179,500	$ 158,000	$ 1,320,860

NOTE 9. *Liquidity Facilities and Other Financing Arrangements*

At December 31, 2004, PSE had short-term borrowing arrangements that included a $350 million unsecured line of credit agreement with a group of banks and a $150 million receivables securitization program. These arrangements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The line of credit agreement allows the Company to make floating rate advances at the banks' prime rate and Eurodollar advances at LIBOR plus a spread, and contains "credit sensitive" pricing with various spreads associated with various credit rating levels. The line of credit agreement also allows for issuing standby letters of credit up to the entire line of credit agreement amount. The line of credit agreement expires in June 2007.

PSE has entered into a Receivables Sales Agreement with Rainier Receivables, Inc., a wholly owned subsidiary of PSE, in December 2002. Pursuant to the Receivables Sales Agreement, PSE sells all of its utility customer accounts receivable and unbilled utility revenues to Rainier Receivables. In addition, Rainier Receivables entered into a Receivables Purchase Agreement with PSE and a third party. The Receivables Purchase Agreement allows Rainier Receivables to sell the receivables purchased from PSE to the third party. The amount of receivables sold by Rainier Receivables is not permitted to exceed $150 million at any time. However, the maximum amount may be less than $150 million depending on the eligible outstanding amount of PSE's receivables which fluctuate with the seasonality of energy sales to customers.

The receivables securitization facility is the functional equivalent of a secured revolving line of credit. In the event Rainier Receivables elects to sell receivables under the Receivables Purchase Agreement, Rainier Receivables is required to pay the purchasers fees that are comparable to interest rates on a revolving line of credit. As receivables are collected by PSE as agent for the receivables purchasers, the outstanding amount of receivables purchased by the purchasers declines until Rainier Receivables elects to sell additional receivables to the purchasers.

The receivables securitization facility expires in December 2005, but is terminable by PSE and Rainier Receivables upon notice to the receivables purchasers. During the year ended December 31, 2004, Rainier Receivables had sold a cumulative amount of $600.2 million in accounts receivable, and had $150.0 million of accounts receivable sold under the program at December 31, 2004. There were no additional amounts available to be sold under the program at December 31, 2004. During the year ended December 31, 2003, Rainier Receivables had sold a cumulative amount of $348.0 million in accounts receivable and had $111.0 million sold under the program at December 31, 2003.

In addition, PSE has agreements with certain 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. PSE also uses commercial paper to fund its short-term borrowing requirements. The following table presents the liquidity facilities and other financing arrangements at December 31, 2004 and 2003.

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2004	2003
Short-term borrowings outstanding:		
InfrastruX bank line of credit borrowings	$ 8,297	$ 13,893
Weighted average interest rate	2.47%	2.59%
Financing arrangements:		
Puget Energy line of credit [1]	$ 15,000	$ 15,000
InfrastruX revolving credit facilities [2]	186,725	184,725
PSE line of credit [3]	350,000	250,000
PSE receivables securitization program [4]	150,000	150,000

[1] *Includes $5.0 million outstanding at December 31, 2004, leaving $10.0 million available under the agreement. On February 1, 2005, Puget Energy reduced the capacity to $5.0 million.*

[2] *The revolving credit facility requires InfrastruX and its subsidiaries to maintain certain financial covenants, including requirements to maintain certain levels of net worth and debt coverage. The agreement also places certain restrictions on expenditures, other indebtedness and executive compensation. For 2004 and 2003, InfrastruX had $143.1 million and $155.6 million outstanding under the credit facilities, effectively reducing available borrowing capacity to $43.6 million and $29.1 million, respectively.*

[3] *Provides liquidity support for PSE's outstanding commercial paper and letters of credit in the amount of $0.5 million in 2004 and 2003, effectively reducing the available borrowing capacity under these credit lines to $349.5 million and $249.5 million, respectively. There was no commercial paper outstanding at December 31, 2004 and 2003.*

[4] *Provides liquidity support for PSE's outstanding letters of credit and commercial paper. At December 31, 2004, PSE had sold $150.0 million in receivables, leaving no amounts available to borrow under the receivables securitization program. At December 31, 2003, PSE had sold $111.0 million in receivables.*

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, 2004 and 2003.

(DOLLARS IN MILLIONS)	2004 Carrying Amount	2004 Fair Value	2003 Carrying Amount	2003 Fair Value
Financial assets:				
Cash	$ 19.8	$ 19.8	$ 27.5	$ 27.5
Restricted cash	1.6	1.6	2.5	2.5
Equity securities	1.9	1.9	3.6	3.6
Notes receivable and other	71.4	71.4	63.6	63.6
Energy derivatives	21.9	21.9	16.2	16.2
Financial liabilities:				
Short-term debt	$ 8.3	$ 8.3	$ 13.9	$ 13.9
Preferred stock subject to mandatory redemption	1.9	1.9	1.9	1.9
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	280.3	290.9	280.3	304.6
Long-term debt – fixed-rate[1]	2,051.4	2,194.8	2,216.3	2,409.6
Long-term debt – variable-rate[1]	200.0	199.9	--	--
Energy derivatives	19.5	19.5	3.6	3.6

[1] *PSE's carrying value and fair value of both fixed-rate and variable-rate long-term debt in 2004 was $2,095.4 million and $2,238.7 million, respectively. PSE's carrying value and fair value of fixed-rate long-term debt in 2003 was $2,053.0 million and $2,250.4 million, respectively.*

The carrying amount of equity securities is considered to be a reasonable estimate of fair value. The fair value of outstanding bonds including current maturities is estimated based on quoted market prices. The fair value of the preferred stock subject to mandatory redemption is estimated based on dealer quotes. The fair value of the junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities is estimated based on dealer quotes. The carrying values of short-term debt and notes receivable are considered to be a reasonable estimate of fair value. The carrying amount of cash, which includes temporary investments with original maturities of three months or less, is also considered to be a reasonable estimate of fair value.

Derivative instruments have been used by the Company on a limited basis and are recorded at fair value. The Company has a policy that financial derivatives are to be used only to mitigate business risk.

In 2003, PSE redeemed the 7.75% mandatorily redeemable preferred stock. 75,000 shares were redeemed in February 2003 at the par value of $100 per share and the remaining 337,500 shares were redeemed in August 2003 at $102.07 per share. Also in 2003, 19,750 shares of the 8.231% Capital Trust I preferred stock were redeemed at $990 per share, leaving 80,250 shares still outstanding. There was no preferred stock redeemed in 2004.

NOTE 11. *Leases*

All of PSE's leases are operating leases. Certain leases contain purchase options and renewal and escalation provisions. Operating and capital lease payments net of sublease receipts were:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	Puget Energy Operating	Puget Energy Capital	PSE Operating
2004	$ 25,751	$ 2,086	$ 17,618
2003	26,842	2,696	19,301
2002	26,386	2,486	20,176

Payments received for the subleases of properties were approximately $0.1 million, $1.4 million and $2.6 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(DOLLARS IN THOUSANDS)	PUGET ENERGY		PSE
AT DECEMBER 31	OPERATING	CAPITAL	OPERATING
2005	$ 19,311	$ 1,988	$ 12,791
2006	19,804	2,057	16,034
2007	17,500	1,558	15,524
2008	15,174	1,032	14,496
2009	11,591	343	11,459
Thereafter	46,140	--	46,045
Total minimum lease payments	$ 129,520	$ 6,978	$ 116,349

PSE leases a portion of its owned gas transmission pipeline infrastructure under a non-cancelable operating lease to a third party. The lease expires in 2009. Future minimum lease payments to be received by PSE under this lease are:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2005	2006	2007	2008	2009
Lease receipts	$ 1,182	$ 1,182	$ 1,182	$ 1,182	$ 985

In 2004, Puget Energy acquired $2.1 million in assets under capital leases, which is a non-cash investing activity for the Statement of Cash Flows for Puget Energy.

NOTE 12. *Income Taxes*

The details of income taxes are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Charged to operating expense:			
Current – federal	$ 7,607	$ 18,119	$ (84,149)
Current – state	75	(2,046)	(774)
Deferred –federal	70,522	56,004	144,230
Deferred – state	(2,647)	927	614
Deferred investment tax credits	(593)	(635)	(661)
Total charged to operations	74,964	72,369	59,260
Charged to miscellaneous income:			
Current	(5,344)	(288)	(3,276)
Deferred	2,470	(1,805)	1,228
Total charged to miscellaneous income	(2,874)	(2,093)	(2,048)
Cumulative effect of accounting change	--	(91)	--
Total income taxes	$ 72,090	$ 70,185	$ 57,212

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Charged to operating expense:			
Current – federal	$ 5,825	$ 22,154	$ (81,839)
Current – state	(21)	(1,460)	(548)
Deferred –federal	71,966	50,880	135,884
Deferred – state	--	--	--
Deferred investment tax credits	(593)	(635)	(661)
Total charged to operations	77,177	70,939	52,836
Charged to miscellaneous income:			
Current	(5,306)	(276)	(3,406)
Deferred	2,470	(1,805)	1,228
Total charged to miscellaneous income	(2,836)	(2,081)	(2,178)
Cumulative effect of accounting change	--	(91)	--
Total income taxes	$ 74,341	$ 68,767	$ 50,658

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

PUGET ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Income taxes at the statutory rate	$ 42,016	$ 65,295	$ 58,846
Increase (decrease):			
Depreciation expense deducted in the financial statements in excess of tax depreciation, net of depreciation treated as a temporary difference	10,723	9,130	10,041
AFUDC included in income in the financial statements but excluded from taxable income	(2,270)	(1,809)	(1,387)
Accelerated benefit on early retirement of depreciable assets	(1,297)	(1,879)	(1,469)
Investment tax credit amortization	(593)	(635)	(661)
Energy Efficiency expenditures - net	(134)	8,096	6,259
Tax benefit of reduced salvage values	--	--	(10,193)
IRS issue resolution	--	(6,209)	--
Goodwill impairment	10,276	--	--
Valuation allowance	17,988	--	--
Preferred stock dividends of subsidiary	--	1,803	2,741
Sate income taxes net of the federal income tax benefit	(2,566)	(877)	(104)
Other - net	(2,053)	(2,730)	(6,861)
Total income taxes	$ 72,090	$ 70,185	$ 57,212
Effective tax rate	62.2%	37.6%	34.0%

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Income taxes at the statutory rate	$ 70,187	$ 66,028	$ 55,862
Increase (decrease):			
Depreciation expense deducted in the financial statements in excess of tax depreciation, net of depreciation treated as a temporary difference	10,723	9,130	10,041
AFUDC included in income in the financial statements but excluded from taxable income	(2,270)	(1,809)	(1,387)
Accelerated benefit on early retirement of depreciable assets	(1,297)	(1,879)	(1,469)
Investment tax credit amortization	(593)	(635)	(661)
Energy Efficiency expenditures - net	(134)	8,096	6,259
Tax benefit of reduced salvage values	--	--	(10,193)
IRS issue resolution	--	(6,209)	--
Sate income taxes net of the federal income tax benefit	(14)	(949)	(356)
Other - net	(2,261)	(3,006)	(7,438)
Total income taxes	$ 74,341	$ 68,767	$ 50,658
Effective tax rate	37.1%	36.5%	31.7%

The Company's deferred tax liability at December 31, 2004, 2003 and 2002 is composed of amounts related to the following types of temporary differences:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Plant and equipment	$ 665,407	$ 622,462	$ 588,182
Capitalized overhead costs	72,448	70,834	72,220
Software amortization	37,484	41,044	41,408
Pensions and compensation	15,367	16,890	29,099
Bonneville Exchange Power	14,078	15,204	15,537
Energy Efficiency charges	10,320	9,446	16,473
Other deferred tax liabilities	68,587	68,351	46,655
Subtotal deferred tax liabilities	883,691	844,231	809,574
Contributions in aid of construction	(41,525)	(46,520)	(44,770)
Goodwill	(18,683)	4,192	2,106
Other deferred tax assets	(30,745)	(46,668)	(36,235)
Subtotal deferred tax assets	(90,953)	(88,996)	(78,899)
Valuation allowance	17,988	--	--
Subtotal net deferred tax assets	(72,965)	(88,996)	(78,899)
Total	$ 810,726	$ 755,235	$ 730,675

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Plant and equipment	$ 645,826	$ 607,203	$ 578,137
Capitalized overhead costs	72,448	70,834	72,220
Software amortization	37,484	41,044	41,408
Pensions and compensation	15,367	16,890	29,099
Bonneville Exchange Power	14,078	15,204	15,537
Energy Efficiency charges	10,320	9,446	16,473
Other deferred tax liabilities	63,926	64,511	43,710
Subtotal deferred tax liabilities	859,449	825,132	796,584
Contributions in aid of construction	(41,525)	(46,520)	(44,770)
Other deferred tax assets	(30,745)	(46,668)	(36,235)
Subtotal deferred tax assets	(72,270)	(93,188)	(81,005)
Total	$ 787,179	$ 731,944	$ 715,579

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 SFAS No. 109, "Accounting for Income Taxes." SFAS 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 ratemaking 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 by PSE. At December 31, 2004, the balance of this asset was $127.3 million.

Puget Energy's management has determined that a portion of the deferred tax asset related to InfrastruX goodwill impairment will not be realized and has provided a valuation allowance of $18.0 million at December 31, 2004 to reduce the deferred tax asset to its estimated realizable value.

NOTE 13. *Retirement Benefits*

The Company has a defined benefit pension plan with a cash balance feature covering substantially all PSE employees. Benefits are a function of age, salary and service. Additionally Puget Energy maintains a non-qualified supplemental retirement plan for officers and certain director-level employees. The annual measurement date is December 31 of each year.

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.

	PENSION BENEFITS		OTHER BENEFITS	
(DOLLARS IN THOUSANDS)	2004	2003	2004	2003
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 400,041	$ 369,692	$ 29,220	$ 31,693
Service cost	10,343	8,284	189	175
Interest cost	24,082	24,406	1,670	1,828
Amendments	--	940	--	--
Actuarial (gain) loss	37,628	19,354	963	(2,194)
Special recognition of prior service costs	--	190	--	--
Benefits paid	(32,357)	(22,825)	(2,050)	(2,282)
Benefit obligation at end of year	$ 439,737	$ 400,041	$ 29,992	$ 29,220

Change in plan assets:				
Fair value of plan assets at beginning of year	$ 428,586	$ 343,960	$ 15,431	$ 16,160
Actual return on plan assets	51,395	79,488	1,184	98
Employer contribution	11,356	27,963	1,394	1,455
Benefits paid	(32,357)	(22,825)	(2,050)	(2,282)
Fair value of plan assets at end of year	$ 458,980	$ 428,586	$ 15,959	$ 15,431
Funded status	$ 19,243	$28,545	$ (14,033)	$ (13,789)
Unrecognized actuarial (gain) loss	72,428	48,217	(2,019)	(2,895)
Unrecognized prior service cost	12,760	15,949	2,403	2,712
Unrecognized net initial (asset) obligation	(163)	(1,267)	3,365	3,783
Net amount recognized	$ 104,268	$ 91,444	$ (10,284)	$ (10,189)
Amounts recognized on statement of financial position consist of:				
Prepaid benefit cost	$ 120,748	$ 112,737	$ --	$ --
Accrued benefit liability	(32,042)	(38,704)	(10,284)	(10,189)
Intangible asset	7,351	9,043	--	--
Accumulated other comprehensive income	8,211	8,368	--	--
Net amount recognized	$ 104,268	$ 91,444	$ (10,284)	$ (10,189)

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the non-qualified pension plan, which has accumulated benefit obligations in excess of plan assets, were $38.9 million, $31.8 million and none, respectively, as of December 31, 2004. For the qualified pension plan the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $400.9 million, $380.0 million and $459.0 million, respectively, as of December 31, 2004.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the non-qualified pension plan which has accumulated benefit obligations in excess of plan assets, were $45.0 million, $38.6 million and none, respectively, as of December 31, 2003. For the qualified pension plan, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $355.1 million, $339.7 million and $428.6 million, respectively, as of December 31, 2003.

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

	Pension Benefits			Other Benefits		
Benefit Obligation Assumptions	2004	2003	2002	2004	2003	2002
Discount rate	5.60%	6.25%	6.75%	5.60%	6.25%	6.75%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	12.00%	9.00%	10.00%

	Pension Benefits			Other Benefits		
Benefit Cost Assumptions	2004	2003	2002	2004	2003	2002
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Return on plan assets	8.25%	8.25%	9.25%	5-8.25%	6-7.00%	6-8.25%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	9.00%	10.00%	6.50%

The Company has used the expected return on plan assets based on an analysis of rates of return over the past 50 years relevant to the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors and adjusted accordingly.

(DOLLARS IN THOUSANDS)	Pension Benefits 2004	2003	2002	Other Benefits 2004	2003	2002
Components of net periodic benefit cost:						
Service cost	$ 10,343	$ 8,284	$ 8,474	$ 189	$ 175	$ 168
Interest cost	24,082	24,406	25,858	1,670	1,828	1,930
Expected return on plan assets	(39,106)	(38,880)	(43,032)	(858)	(934)	(906)
Amortization of prior service cost	3,189	3,220	2,990	309	309	90
Recognized net actuarial gain	1,128	(2,688)	(5,120)	(239)	(341)	(229)
Amortization of transition (asset) obligation	(1,104)	(1,104)	(1,136)	418	418	470
Plan curtailment	--	--	(1,353)	--	--	1,691
Special recognition of prior service costs	--	190	1,683	--	--	--
Net pension benefit cost (income)	$ (1,468)	$ (6,572)	$(11,636)	$ 1,489	$ 1,455	$ 3,214

The aggregate expected contributions by the Company to fund the pension and other benefit plans for the year ended December 31, 2005 are $2.0 million and $1.4 million, respectively. The full amount of the pension funding for 2005 is for the Company's non-qualified supplemental retirement plan.

The fair value of the plan assets of the pension benefits and other benefits are invested as follows at December 31:

	2004		2003	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Short-term investments and cash	2.4%	100.0%	3.0%	100.0%
Equity securities	67.8%	--	63.8%	--
Fixed income securities	18.2%	--	22.9%	--
Mutual funds (equity and fixed income)	11.6%	--	10.3%	--

The expected total benefits to be paid under both plans for the next five years and the aggregate total to be paid for the five years thereafter is as follows:

(DOLLARS IN THOUSANDS)	2005	2006	2007	2008	2009	2010-2014
Total benefits	$29,768	$30,202	$31,256	$32,904	$33,253	$180,516

The assumed medical inflation rate used to determine benefit obligations is 12.0% in 2005 grading to 6.0% in 2011. A 1% change in the assumed medical inflation rate would have the following effects:

	2004		2003	
(DOLLARS IN THOUSANDS)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 552	$ (477)	$ 589	$ (529)
Effect on service and interest cost components	31	(28)	38	(35)

The Company has a Retirement Committee that establishes investment policies, objectives and strategies for the purpose of obtaining the optimum return for the pension benefit plans, while also keeping with the assumption of prudent risk and the Retirement Committee's total return objectives. All changes to the investment policies are reviewed and approved by the Retirement Committee prior to being implemented.

The Retirement Committee contracts with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Committee has established investment allocation percentages by asset classes as follows:

Asset Class	Allocation Minimum	Target	Maximum
Short-term investments and cash	--	--	5%
Equity securities	40%	70%	95%
Fixed-income securities	20%	30%	40%
Real estate	--	--	10%

NOTE 14. *Employee Investment Plans*

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.

Puget Energy's contributions to the Employee Investment Plans were $7.6 million, $7.1 million and $6.9 million for the years 2004, 2003 and 2002, respectively.

PSE's contributions to the Employee Investment Plan were $6.3 million, $6.1 million and $6.1 million for the years 2004, 2003 and 2002, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

NOTE 15. *Stock-based Compensation Plans*

The Company has various stock compensation plans which, prior to 2003, were accounted for according to APB No. 25, "Accounting for Stock Issued to Employees," and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation." In 2003, the Company adopted the fair value based accounting of SFAS No. 123 using the prospective method under the guidance of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company applies SFAS No. 123 accounting to stock compensation awards granted from 2003 on, while grants that were made in years prior to 2003 are accounted for using the intrinsic value method of APB No. 25. Total compensation expense related to the plans was $4.1 million, $6.4 million and $6.3 million in 2004, 2003 and 2002, respectively.

The Company's shareholder-approved Long-Term Incentive Plan (LTI Plan) encompasses many of the awards granted to employees. Established in 1995 and amended and restated in 1997, the LTI Plan applies to officers and key employees of the Company. Awards granted under this plan include stock awards, performance awards or other stock-based awards as defined by the plan. Any shares awarded are purchased on the open market. The maximum number of shares that may be purchased for the LTI Plan is 1,200,000.

Performance Share Grants

Each year the Company awards performance share grants under the LTI Plan. These are granted to key employees and vest at the end of three years for grants made in 2004 and four years for grants made prior to 2004 with the final number of shares awarded, and total expense recorded, depending on a performance measure. Compensation expense related to performance share grants was $2.5 million, $5.1 million and $5.5 million for 2004, 2003 and 2002, respectively. The fair value of the performance awards granted in 2004, 2003 and 2002 was $19.70, $17.29 and $14.82, respectively. There were a total of 272,307 performance awards granted in 2004 of which 16,046 were also forfeited in 2004. In 2003 and 2002 there were 349,912 and 248,158 awards granted, respectively, of which 79,749 and 40,640, respectively, have been forfeited to date. As of December 31, 2004, there are four active grant cycles for a total of 730,786 share grants outstanding although they may not all be awarded.

Stock Options

In 2002, Puget Energy's Board of Directors granted 40,000 stock options under the LTI Plan and an additional 260,000 options outside of the LTI Plan (for a total of 300,000 non-qualified stock options) to the president and chief executive officer. These options can be exercised at the grant date market price of $22.51 per share and vest yearly over four and five years although vesting is accelerated under certain conditions. The options expire 10 years from the grant date. All 300,000 options remained outstanding at December 31, 2004, with 135,000 options exercisable. At December 31, 2003 and 2002, 67,500 options and 0 options, respectively, were exercisable. The fair value of the options at the grant date was $3.37 per share. Following the intrinsic value method of APB 25, no compensation expense was recorded for these options.

RESTRICTED STOCK AND RESTRICTED STOCK UNITS

In 2004, 2003 and 2002 the Company granted 40,000 shares, 11,000 shares and 30,000 shares, respectively, of restricted stock under the LTI Plan to be purchased on the open market. The 2004 grant vests 8,000 shares in three years, 12,000 shares in four years and the remaining 20,000 shares in five years. Of the 2003 shares issued, 1,000 vested in 2003 with the remaining shares vesting evenly over the following five years. The 2002 shares were fully vested as of December 2003. In 2002, the Company also issued 50,000 shares of restricted stock outside of the LTI Plan as approved by the Puget Energy Board of Directors. These shares were recorded as a separate component of stockholders' equity and vest evenly over a five-year period. Compensation expense related to the restricted shares was $0.5 million, $0.6 million and $0.5 million in 2004, 2003 and 2002, respectively. Dividends are paid on all outstanding restricted stock and are accounted for as a Puget Energy common stock dividend, not as compensation expense. The weighted average grant date fair value for all outstanding shares of restricted stock granted in 2004, 2003 and 2002 was $23.55, $23.29 and $21.94, respectively.

In 2004, the Company also granted 10,000 restricted stock units outside of the LTI Plan but subject to the terms and conditions of the plan. The units vest 2,000 shares in three years, 3,000 shares in four years and the remaining 5,000 shares in five years. These will be settled in cash as they become vested. Dividends are paid on the outstanding stock units and are accounted for as compensation expense. Compensation expense related to the restricted stock units agreement was $0.1 million in 2004. The weighted average grant date fair value for the restricted stock units was $23.55.

RETIREMENT EQUIVALENT STOCK

The Company has a retirement equivalent stock agreement in which in lieu of participating in the Company's executive supplemental retirement plan the president and chief executive officer is granted performance-based stock equivalents in January of each year, which are deferred under the Company's deferred compensation plan. In 2004 and 2003 the Company awarded 6,469 and 4,319 shares, respectively, which vest over a period of seven years from January 1, 2002 at 15% per year for the first six years and the remaining 10% in the seventh year. Dividends are paid on the stock equivalents accumulated in the deferred compensation account in the form of Puget Energy common stock, which is added to the deferred compensation account. Compensation expense related to the retirement equivalent stock agreement was $0.1 million in 2004 as well as in 2003. The weighted average grant date fair value for the retirement equivalent stock was $23.77 and $22.05 for 2004 and 2003 respectively. There were no grants in 2002.

EMPLOYEE STOCK PURCHASE PLAN

The Company has a shareholder-approved Employee Stock Purchase Plan (ESPP) open to all employees. Offerings occur at six-month intervals at the end of which the participating employees receive shares for 85% of the lower of the stock's fair market price at the beginning or the end of the six-month period. A maximum of 500,000 shares may be sold to employees under the plan. In 2004 and 2003, 52,716 and 38,940 shares were issued for the ESPP, respectively. In 2002, 18,252 shares were issued and 19,407 shares were purchased for the plan. At December 31, 2004, 206,946 shares may still be sold to employees under the plan. Under the SFAS No. 123 accounting that the Company adopted in 2003, ESPP is considered to be compensation expense. Total compensation expense related to the ESPP was $0.2 million in 2004 and $0.2 million in 2003. Dividends are not paid on ESPP shares until they are purchased by employees and thus are accounted for as dividends, not compensation expense. The weighted average fair value of the purchase rights granted in 2004, 2003 and 2002 was $3.74, $4.25 and $4.19, respectively.

INFRASTRUX STOCK OPTION PLAN

The InfrastruX stock option plan, established in 2000, has 3,862,500 shares of InfrastruX stock authorized to be granted to officers, key employees and non employee directors of InfrastruX. The options generally vest within four years and expire 10 years from the grant date. The following summarizes InfrastruX option information for 2004, 2003 and 2002:

	2004		2003		2002	
	Shares (in thousands)	Weighted Average Exercise Price	Shares (in thousands)	Weighted Average Exercise Price	Shares (in thousands)	Weighted Average Exercise Price
Outstanding at beginning of year	2,618	$4.36	2,643	$4.31	1,995	$4.05
Granted	10	5.00	176	5.00	725	5.00
Exercised	--	--	--	--	--	--
Canceled	(99)	4.75	(201)	4.20	(77)	4.09
Outstanding at end of year	2,529	$4.35	2,618	$4.36	2,643	$4.31
Options exercisable at year end	2,056	$4.20	1,837	$4.12	802	$4.02
Weighted average fair value of options granted during the year	$2.41		$2.41		$2.23	

The following summarizes InfrastruX's outstanding option information at December 31, 2004:

	Shares Outstanding (in thousands)	Weighted Average Contractual Life (in years)	Weighted Average Exercise Price
Exercise Prices			
$4.00	1,641	6.10	$ 4.00
$5.00	888	7.47	5.00
	2,529	6.59	$ 4.35

Stock options awarded under the InfrastruX plan were generally granted at the InfrastruX market price on the date of grant although some options were granted at a discount requiring InfrastruX to record compensation expense. With those options and the prospective adoption of SFAS No. 123 fair value accounting in 2003, InfrastruX recorded compensation expense related to options granted in 2004, 2003 and 2002 of $0.1 million, $0.2 million and $0.1 million, respectively.

NON EMPLOYEE DIRECTOR STOCK PLAN

The Company has a director stock plan approved in 1997 and effective beginning in 1998, for all non employee directors of Puget Energy and PSE. Under the plan, which has a 10-year term, and which, subject to shareholder approval, will be amended and restated at the May 2005 Annual Meeting, non employee directors receive a minimum of two-thirds of their quarterly retainer fees in Puget Energy stock except that 100% of quarterly retainers are paid in Puget Energy stock until the director holds a number of shares equal in value to two years of their retainer fees. Directors may optionally receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.6 million, $0.4 million and $0.2 million in 2004, 2003 and 2002, respectively. The Company issues new shares or purchases stock for this plan on the open market up to a maximum of 100,000 shares. As of December 31, 2004, 15,230 shares had been issued or purchased for the director stock plan and 64,838 deferred, for a total of 80,068 shares. As of December 31, 2003 and 2002 the number of shares that had been purchased for the director stock plan was 9,902 and 6,916, respectively, and the number that had been deferred was 48,219 and 36,117, respectively, for a total of 58,121 and 43,033 shares, respectively.

The Company used the Black-Scholes option pricing model to determine the fair value of certain stock-based awards to employees. The following assumptions were used for awards granted in 2004, 2003 and 2002:

	2004	2003	2002
Stock options			
Risk-free interest rate	--	--	4.32%
Expected lives – years	--	--	4.50
Expected stock volatility	--	--	23.62%
Dividend yield	--	--	5.00%
InfrastruX stock option plan			
Risk-free interest rate	2.8%	2.8%	4.05%
Expected lives – years	4.0	4.0	4.0
Expected stock volatility	70.0%	70.0%	70.0%
Performance awards			
Risk-free interest rate	2.59%	2.35%	4.0%
Expected lives – years	3.0	4.0	4.0
Expected stock volatility	22.24%	23.85%	23.71%
Dividend yield	4.45%	4.86%	8.85%
Employee Stock Purchase Plan			
Risk-free interest rate	1.28%	1.07%	1.65%
Expected lives - years	0.5	0.5	0.5
Expected stock volatility	9.89%	19.47%	26.97%
Dividend yield	4.42%	4.39%	5.81%

NOTE 16. *Accounting for Derivative Instruments and Hedging Activities*

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. The Company enters into both physical and financial contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts, option contracts and swaps. The majority of these contracts qualify for the normal purchase normal sale exception. Those contracts that do not meet normal purchase normal sale exception or cash flow hedge criteria are marked-to-market to current earnings in the income statement, subject to deferral under SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation," (SFAS No. 71) for energy related derivatives due to the Power Cost Adjustment (PCA) mechanism.

The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy risk management function monitors and manages these risks using analytical models and tools.

The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore, wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

The Company's energy risk management staff develops hedging strategies for the Company's energy supply portfolio. The first priority is to obtain reliable supply for delivery to the Company's retail customers. The second priority is to protect against unwanted risk exposure. The third priority is to optimize excess capacity or flexibility within the energy portfolio.

The Company has entered into master netting agreements with counterparties when available to mitigate credit exposure to those counterparties. The Company believes that entering into such agreements reduces risk of settlement default for the ability to make only one net payment. In addition, the Company believes risk is mitigated with an improved position in potential counterparty bankruptcy situations due to a consistent netting approach.

At December 31, 2004, the Company was subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

For the year ended December 31, 2004, the Company recorded an increase in earnings of approximately $0.5 million compared to a decrease of $0.1 million for 2003. Of the 2004 gain, $0.7 million unrealized gain represented cash flow hedges that were de-designated and reclassified from other comprehensive income into earnings. As of December 31, 2004, the Company had an unrealized loss recorded in other comprehensive income of $6.5 million after-tax related to contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. In 2004, a portion of the total unrealized gain of cash flow hedge transactions in other comprehensive income and marked-to-market gain in the income statement were deferred under SFAS No. 71 due to the Company expecting to reach the $40 million cap under the PCA mechanism in the first quarter 2005. When these transactions are realized they will be reflected in the PCA mechanism calculation. As of December 31, 2003, the Company had an unrealized gain recorded in other comprehensive income of $0.2 million (net of tax) related to energy contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. The amount of cash flow hedges associated with these energy contracts that will reverse and be settled into the income statement during 2005 is approximately $0.7 million.

PSE has a contract with a counterparty whose debt ratings have been below investment grade since 2002. The contract, a physical gas supply contract for one of PSE's electric generating facilities, was marked-to-market beginning in the fourth quarter 2003. Although the counterparty continues to fully perform on the physical supply contract, the counterparty's credit ratings have remained weak. Prior to October 1, 2003, the contract was designated as a normal purchase under SFAS No. 133. PSE has concluded that it is appropriate to reserve the mark-to-market gain on this contract due to the credit quality of the counterparty in accordance with SFAS No. 133 guidance, as management deemed that delivery is not probable through the term of the contract, which expires December 2008. There was no impact on earnings for the 12 months ended December 31, 2004 and 2003.

In the first quarter 2004, the counterparty of another physical gas supply contract for one of PSE's electric generating facilities notified PSE that it would be unable to deliver physical gas supply beginning in November 2005 through the end of the contract in June 2008. Since physical delivery for the life of the contract was no longer probable, the contract no longer met the criteria for normal purchase exception under SFAS No. 133. Therefore, the contract was marked-to-market in the first quarter 2004, with an offsetting reserve for the portion of the mark-to-market gain applicable to the impaired period of November 2005 through June 2008. In October 2004, PSE and the counterparty reached a settlement on the non-deliverable period of November 2005 through June 2008. The agreement allows PSE to recover a portion of the present value of the difference in future market prices of physical gas and the original contract price, for a total recovery of approximately $10.1 million. In the fourth quarter 2004, an accounting order was approved by the Washington Commission to defer the counterparty settlement amount as a regulatory liability and amortize the benefit over the period of November 2005 through June 2008 as a reduction in Electric Generation Fuel expense. The amended contract meets the criteria for normal purchase exception under SFAS No. 133 since delivery for the life of the contract is probable. In October 2004, PSE entered into a new contract with another counterparty for the period November 2005 through June 2008 to replace the physical gas supply from the previously mentioned amended contract. This new contract meets the normal purchase exception under SFAS No. 133.

The Company entered into treasury lock transactions to hedge against the potential rising treasury rate component of the interest rate on planned debt issuances. The purpose of the treasury lock is to lock in the base component of the interest rate on the planned issuance at current period favorable levels.

In the third quarter 2004, the Company entered into two treasury lock contracts to hedge against potential rising interest rate exposure for a debt offering anticipated to be performed in the first half of 2005. A treasury lock is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a 30 year treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the treasury lock instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decrease related to the hedged debt from the date of issuance of the treasury lock instruments, the Company would pay the counterparty for the change in bond value. These treasury lock contracts were designated under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. When these treasury lock contracts are settled upon issuance of debt, any gain or loss will be amortized from other comprehensive income to interest expense over the 30 year life of the issued debt. At December 31, 2004, the unrealized loss associated with these two treasury lock contracts was $11.3 million ($7.4 million net of tax) and is included in other comprehensive income. Both treasury rate lock hedges will settle in 2005.

NOTE 17. *Acquisitions (Puget Energy Only)*

During 2002, InfrastruX acquired 100% of three companies based in Texas for a total price of $49.7 million, and during the second quarter 2003 acquired 100% of one additional company based in New Mexico for $11.8 million. InfrastruX made no acquisitions in 2004. All purchases were funded in the form of cash and preferred or common stock.

These companies provide utility infrastructure services which are relevant to InfrastruX's operating strategy including: installing, replacing and restoring underground cables and pipes for utilities and telecommunications providers; pipeline construction, maintenance and rehabilitation services for the natural gas and petroleum industries, including directional drilling and vacuum excavation; and distribution and transmission-oriented overhead electric construction services to electric utilities and cooperatives.

The acquisitions have been accounted for using the purchase method of accounting and, accordingly, the operating results of these companies have been included in Puget Energy's consolidated financial statements since their acquisition dates. Goodwill additions representing the excess of cost over the net tangible and identifiable intangible assets at the time of purchase were approximately $7.7 million in 2003 and $23.5 million in 2002. Of the additions to goodwill in 2003 and 2002, no amounts were deductible for calculating income tax expense.

The pro forma combined revenue, net income and earnings per common share of Puget Energy presented below give effect to the acquisitions as if they had occurred on January 1, 2002. These results are not necessarily indicative of the results of operations that would have occurred had the acquisitions of these companies been consummated for the period for which they are being given effect. There were no acquisitions in 2004.

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS) (UNAUDITED) FOR THE YEARS ENDED DECEMBER 31	2003	2002
Operating revenues	$ 2,396,802	$ 2,391,981
Net income	116,636	112,813
Basic earnings per common share	$ 1.23	$ 1.28
Diluted earnings per common share	$ 1.22	$ 1.27

NOTE 18. *Goodwill and Intangibles (Puget Energy Only)*

Effective January 1, 2002, Puget Energy adopted SFAS No. 142, "Goodwill and Other Intangible Assets," which required all goodwill amortization to cease on January 1, 2002. Puget Energy allocates goodwill to reporting units based on the excess purchase price over tangible and identifiable intangible assets. SFAS No. 142 also requires Puget Energy to perform an annual impairment review of goodwill. In addition to the annual review, Puget Energy is required to perform an impairment review at the time an event or circumstance arises that would indicate the fair value would be below its carrying value. In the fourth quarter 2004, as part of its annual goodwill review, Puget Energy recorded a non-cash goodwill impairment of $91.2 million ($76.6 million after tax and after minority interest) to operating expenses related to its investment in InfrastruX. The valuation of the goodwill was based on the present value of the future cash flows of estimated earnings of InfrastruX which reflect prospective market price information from prospective buyers. In 2004, Puget Energy began evaluating its strategic options for its InfrastruX investment and on February 8, 2005 Puget Energy decided to exit this utility construction services business.

Identifiable assets acquired as a result of acquisitions of companies are amortized based on the expected pattern of use or on a straight-line basis over the expected periods to be benefited, which ranges from 5 to 20 years. In 2004, a patent was completed and added to intangibles for $0.1 million with an amortization period of 16 years. In 2003, a total of $2.1 million was added to intangible assets – assigned $0.1 million to patents with an amortization period of 17 years, $1.7 million to contractual customer relationships with an amortization period of 10 years and $0.3 million to covenant not to compete with an amortization period of five years. The total weighted average amortization period for the 2003 additions is 9.6 years.

AT DECEMBER 31, 2004 (DOLLARS IN THOUSANDS)	Gross Intangibles	Accumulated Amortization	Net Intangibles
Covenant not to compete	$ 4,178	$ 2,748	$ 1,430
Developed technology	14,190	3,163	11,027
Contractual customer relationships	4,702	1,374	3,328
Patents	986	91	895
Total	$ 24,056	$ 7,376	$ 16,680

AT DECEMBER 31, 2003 (DOLLARS IN THOUSANDS)	Gross Intangibles	Accumulated Amortization	Net Intangibles
Covenant not to compete	$ 4,178	$ 2,009	$ 2,169
Developed technology	14,190	2,454	11,736
Contractual customer relationships	4,702	747	3,955
Patents	915	68	847
Total	$ 23,985	$ 5,278	$ 18,707

The identifiable intangible amortization expense for the year ended December 31, 2004 was $2.1 million compared to $2.1 million and $1.9 million for 2003 and 2002, respectively. The identifiable intangible assets amortization for future periods based on the current acquisitions will be:

(DOLLARS IN THOUSANDS)	2005	2006	2007	2008	2009
Future intangible amortization	$ 2,207	$1,732	$1,385	$1,301	$1,276

NOTE 19. *Tenaska Disallowance*

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a disallowance of $25.6 million for the PCA 1 period (July 1, 2002 through June 30, 2003), which was recorded by PSE as a Purchased Electricity expense in the second quarter 2004. The order also established guidelines for future recovery of Tenaska costs. The amounts were determined to be a $25.6 million disallowance for the PCA 1 period and an estimated disallowance of $11.3 million for the PCA 3 period (July 1, 2004 to June 30, 2005), based upon applying the Washington Commission's methodology of 50% disallowance on the return on the Tenaska regulatory asset due to projected costs exceeding the benchmark during the period. For the PCA 3 period, approximately $5.6 million was disallowed in the period July 1, 2004 through December 31, 2004, primarily as a reduction to Electric Operating Revenue. While the Washington Commission did not expressly address the disallowance for the PCA 2 period (July 1, 2003 through June 30, 2004), PSE estimated the disallowance for the PCA 2 period to be approximately $12.2 million if the Washington Commission were to follow the same methodology as they have ordered for the PCA 3 period. Therefore, PSE recorded a $12.2 million disallowance to Purchased Electricity expense in the second quarter 2004 for the 50% disallowance of the return on the Tenaska regulatory asset in accordance with the Washington Commission's methodology discussed in their order of May 13, 2004 for a cumulative impact on earnings of $43.4 million in 2004 for the PCA 1, PCA 2 and PCA 3 periods. As a result of the disallowance recorded, the PCA customer deferral was expensed and a reserve was established for amounts not previously deferred under the PCA mechanism. The reserve balance as of December 31, 2004 was $3.2 million, which is expected to be utilized in 2005 as excess power costs are shared through the PCA mechanism.

PSE filed the PCA 2 period compliance filing in August 2004 and received an order from the Washington Commission on February 23, 2005. In the PCA 2 compliance order, the Washington Commission approved the Washington Commission staff's recommendation for an additional return related to the Tenaska regulatory asset in the amount of $6.1 million related to the period July 1, 2003 through December 31, 2003. Washington Commission staff's recommendation was opposed by certain other parties. This amount alters the PCA deferral and is subject to reconsideration and appeal by other parties. Parties have 10 days from February 23, 2005 to file for reconsideration and 30 days to appeal the order. Once the statutory appeal process has concluded and the Washington Commission issues its final order, PSE will determine if recording a regulatory asset is appropriate.

In the May 13, 2004 order, the Washington Commission established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

Below is a summary of the Tenaska disallowances by quarter through December 31, 2004:

(DOLLARS IN MILLIONS) QUARTER ENDING	7/02 - 6/03 PCA 1 (ordered/final)	7/03 - 6/04 PCA 2 (estimated)	7/04 - 12/04 PCA 3 (estimated)	Total
June 30, 2004	$ 25.6	$ 12.2	$ --	$ 37.8
September 30, 2004	--	--	2.8	2.8
December 31, 2004	--	--	2.8	2.8
Total	$ 25.6	$ 12.2	$ 5.6	$ 43.4

The Washington Commission guidelines for determining future recovery of the Tenaska costs (gas costs, recovery of the Tenaska regulatory asset and return on the Tenaska regulatory asset) are as follows:

1. The Washington Commission will determine if PSE's gas purchasing plan and gas purchases for Tenaska are prudent through the PCA compliance filings.
2. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, and if PSE's actual Tenaska costs fall at or below the benchmark, it will recover fully its Tenaska costs.
3. If PSE's gas purchasing plan and gas purchases for Tenaska are prudent, but its actual Tenaska costs exceed the benchmark, PSE will only recover 50% of the lesser of:
   a) actual Tenaska costs that exceed the benchmark or;
   b) the return on the Tenaska regulatory asset.
4. If PSE's gas purchasing plan or gas purchases are found to be imprudent in a future proceeding, PSE risks disallowance of any and all Tenaska costs.

The Washington Commission confirmed that if the Tenaska gas costs are deemed prudent, PSE will recover the full amount of actual gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded.

NOTE 20. *Colstrip Matters*

In September 2004, the owners of Colstrip Units 1 & 2 (PSE and PPL Montana) entered into a tentative settlement agreement with certain homeowners in the Colstrip town site area concerning a lawsuit filed in May 2003. In December 2004, the plaintiffs retained new counsel and postponed further settlement discussions until more discovery is completed. The lawsuit alleged certain domestic water wells may have been contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond. The tentative settlement agreement would require extending municipal water to the homeowners and abandoning the existing wells. The total estimated cost of the settlement ranges from $1.4 million to $1.5 million. As a result of this tentative settlement agreement, PSE recorded a $0.7 million reserve in the third quarter 2004 for its 50% ownership of the Colstrip Units 1 & 2 project. The settlement agreement would not resolve certain other claims by residents within the city limits. PSE cannot predict the outcome or any potential financial impact of the claims by the residents within the city limits at this time.

In June 2004, PSE and Western Energy Company (WECO), the supplier of coal to Colstrip Units 1 & 2, entered into a binding arbitration and settled a dispute concerning prices paid for coal supplied. The binding decision retroactively set a new baseline cost per ton of coal purchased by PSE for Colstrip Units 1 & 2 supplied from July 31, 2001, and is applicable for the remaining term of the coal supply agreement through December 2009. The decision resulted in a $6.9 million charge that was recorded in the second quarter 2004. Of the $6.9 million charge, $5.0 million was included in the PCA mechanism. PSE had previously accrued a $1.6 million reserve in the fourth quarter 2003 related to the arbitration.

On April 29, 2004, the Minerals Management Service of the United States Department of the Interior (MMS) issued an order to WECO to pay additional royalties concerning coal purchased by PSE for Colstrip Units 3 & 4. The order seeks payment of an additional $1.1 million in royalties for coal mined from federal land between 1997 and June 30, 2000. During that period, PSE's coal price was reduced by a settlement agreement entered into in February 1997 among PSE, WECO and Montana Power Company that resolved disputes that were then pending. The order seeks to impute the price charged to PSE based on the other Colstrip Units 3 & 4 owners' contractual amounts. PSE is supporting WECO's appeal of the order, but is also evaluating the basis of the claim. PSE accrued a loss reserve in the amount of $1.1 million in connection with this matter in the second quarter 2004.

In addition, the MMS issued two orders to WECO in 2002 and 2003 to pay additional royalties concerning coal sold to Colstrip Units 3 & 4 owners. The orders assert that additional royalties are owed as a result of WECO not paying royalties in connection with revenue received by WECO from the Colstrip Units 3 & 4 owners under a coal transportation agreement during the period October 1, 1991 through December 31, 2001. PSE's share of the alleged additional royalties is $1.8 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. Other parties may attempt to assert claims against WECO if the MMS position prevails. The transportation agreement provides for the construction and operation of a conveyor system that runs several miles from the mine to Colstrip Units 3 & 4. WECO has appealed these orders and PSE is monitoring the process. PSE believes that Colstrip Units 3 & 4 owners have reasonable defenses in this matter based upon its review. Neither the outcome of this matter nor the associated costs can be predicted at this time.

On December 5, 2003, Colstrip Units 1 & 2 and 3 & 4 received an information request from the Environmental Protection Agency (EPA) relating to their compliance with the Clean Air Act New Source Review regulations. PSE is currently in discussions with the EPA concerning the information request. Neither the outcome of this matter nor any potential associated costs can be predicted at this time.

NOTE 21. *Taxes Other Than Income Taxes*

PUGET ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Taxes other than income taxes:			
Real estate and personal property	$ 45,121	$ 45,660	$ 48,890
State business	82,408	75,523	77,527
Municipal and occupational	72,405	64,861	67,770
Other	39,479	38,273	37,029
Total taxes other than income taxes	$ 239,413	$ 224,317	$ 231,216
Charged to:			
Operating expense	$ 221,980	$ 208,395	$ 215,429
Other accounts, including construction work in progress	17,433	15,922	15,787
Total taxes other than income taxes	$ 239,413	$ 224,317	$ 231,216

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2004	2003	2002
Taxes other than income taxes:			
Real estate and personal property	$ 43,843	$ 44,757	$ 48,408
State business	82,408	75,524	77,527
Municipal and occupational	72,405	64,861	67,770
Other	27,766	25,638	24,463
Total taxes other than income taxes	$ 226,422	$ 210,780	$ 218,168
Charged to:			
Operating expense	$ 208,989	$ 194,857	$ 202,381
Other accounts, including construction work in progress	17,433	15,923	15,787
Total taxes other than income taxes	$ 226,422	$ 210,780	$ 218,168

NOTE 22. *Other*

On September 24, 2004, the Washington Commission approved PSE's request for a Purchased Gas Adjustment (PGA) mechanism rate increase filed on August 31, 2004. The approved request will increase rates and revenues by approximately 17.6% or $121.7 million annually. The increase in PGA mechanism rates was to recover higher market prices of natural gas sold to customers. The PGA mechanism passes through to customers increases or decreases in the gas supply portion of the natural gas service rates based upon changes in gas prices. PSE's gas margin and net income are not affected by the change in PGA mechanism rates.

In 2003, the Washington Commission's Pipeline Safety staff conducted a natural gas standard inspection for three counties within Washington State in which PSE operates gas pipelines. The inspection included a review of procedures, records and operations and maintenance activities. On June 29, 2004, the Washington Commission issued a complaint to PSE related to that inspection, alleging certain violations of Washington Commission regulations. In December 2004, PSE and the Washington Commission resolved the issues. PSE agreed to a penalty of $0.5 million, and also agreed to update certain natural gas operating practices. In addition, the resolution included the potential for future penalties of up to $0.2 million in the next ten years if certain operational goals are not met. The Washington Commission approved the settlement on January 31, 2005.

In September 2004, a natural gas fire destroyed a home and took the life of a PSE customer. The cause of the fire remains under investigation by PSE, the Washington Commission and other parties. PSE has tendered the matter to its general liability insurer. Neither the potential regulatory nor litigation outcomes of this matter nor the final associated costs can be predicted at this time.

On February 18, 2005, the Washington Commission approved a 3.5% general tariff gas rate case increase and a 4% general tariff electric rate case increase. The increases were $26.3 million annually for gas customers and $56.6 million for electric customers effective March 4, 2005. In the order, the Washington Commission also approved a capital structure of 43% common equity with a return on common equity of 10.3%.

On April 23, 2004, the acquisition of a 49.85% interest in the Frederickson 1 generating facility was approved by FERC. Prior to that approval, on April 7, 2004, the Washington Commission had issued an order in PSE's power cost only rate case granting approval for the acquisition of the Frederickson 1 generating facility. As a result of these approvals, PSE completed the acquisition in the second quarter 2004 and added $80.8 million in utility plant. In its order, the Washington Commission found the acquisition to be prudent and the costs associated with the generating facility reasonable. The costs associated with the generating facility, including projected baseline gas costs, are approved for recovery in rates. On May 13, 2004, the Washington Commission also approved other adjustments to power costs that resulted in an increase of cost recovery in rates of $44.1 million annually, beginning May 24, 2004, which includes the ownership, operation and fuel costs of the Frederickson 1 generating facility.

In December 2003, PSE notified FERC that it rejected the 1997 license for the White River project because the 1997 license contained terms and conditions that rendered ongoing operations of the project uneconomical relative to alternative resources. As a result, generation of electricity ceased at the White River project on January 15, 2004. At December 31, 2004, the White River project net book value totaled $65.1 million, which included $46.4 million of net utility plant, $14.8 million of capitalized FERC licensing costs, $3.1 million of costs related to construction work in progress and $0.8 million related to dam operation and safety. PSE is sought recovery of the relicensing, other construction work in progress and dam operations and safety costs totaling $18.7 million in its general rate filing of April 2004, over a 10-year amortization period. In the third quarter 2004, the Washington Commission staff recommended that PSE be allowed recovery of the White River net utility plant costs noted above, but defer any amortization of the FERC licensing and other costs until all costs and any sales proceeds are known. In its February 18, 2005 general rate case order, the Washington Commission found this treatment reasonable, and adopted all of the staff recommendations.

PSE has minority ownership interests in a venture capital fund established as a limited liability corporation that seeks long-term capital appreciation by making capital investments in energy sector related businesses. The Company's ownership interest in the fund is less than 20% and the managing members of the limited liability corporation have sole discretion over fund operations, management and investment decisions. Under the terms of the limited liability corporation agreement establishing the fund, the fund terminates December 31, 2007. The Company's carrying value of the investment in the fund totaled $1.9 million at December 31, 2004, which includes a $6.1 million pre-tax loss on the Company's original cost basis in the fourth quarter 2003. Based on the guidance from EITF No. 03-16, the Company started accounting for its investment in the fund using the equity method accounting. The adoption of the equity method had no cumulative effect on earnings for the year ended December 31, 2004 as PSE had been carrying this investment at fair value, which represents the equity basis, since December 31, 2003. The Company's future funding obligation to this fund is $0.3 million.

On November 1, 1999, PSE acquired Encogen Northwest, LP (Encogen) whose sole asset is a natural gas-fired cogeneration facility located in Washington State. With the approval of the Washington Commission, the Encogen facility has been operated as part of PSE's least cost generation dispatch portfolio to serve its native load obligations since it was acquired in 1999. Two wholly-owned subsidiaries of PSE, GP Acquisition Corporation and LP Acquisition Corporation, are the general and limited partners of Encogen, respectively. On December 29, 2004, PSE filed an application with FERC pursuant to Section 203 of the FPA to transfer the Encogen facility to PSE and eliminate the various subsidiaries via an Agreement and Plan of Merger (Merger). On February 15, 2005, FERC issued an order authorizing the Encogen plant to be transferred to PSE. PSE anticipates completing the merger in 2005.

NOTE 23. *Commitments and Contingencies*

For the year ended December 31, 2004, approximately 23.1% of the Company's energy output was obtained at an average cost of approximately $0.0146 per kWh through long-term contracts with several of the Washington Public Utility Districts (PUDs) owning hydroelectric projects on the Columbia River.

The purchase of power from the Columbia River projects is 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, 2004, 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	Total Bonds Outstanding 12/31/04 [2] (Millions)	Company's Annual Amount Purchasable (Approximate) % of Output	Megawatt Capacity	Cost [3] (Millions)
Rock Island						
Original units	2012	2029	$ 115.8	50.0	414	$ 40.8
Additional units	2012	2029	328.4	75.0		
Rocky Reach	2011	2006	383.0	38.9	505	24.7
Wells	2018	2012	143.3	31.3	261	5.2
Priest Rapids [4]	2005	2005	179.7	8.0	72	2.4
Wanapum [4]	2009	2005	181.6	10.8	98	3.3
Total			$ 1,331.8		1,350	$ 76.4

[1] *The Company is unable to predict whether the licenses under the Federal Power Act will be renewed to the current licensees. FERC has issued orders for the 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: 53.4% at Rock Island; 60.0% at Rocky Reach; and 6.6% at Wells. There are no maturities beyond the contract expiration date of 2035 for Priest Rapids and Wanapum which assumes a 40-year FERC license extension.*

[3] *The components of 2004 costs associated with the interest portion of debt service are: Rock Island, $22.6 million for all units; Rocky Reach, $9.4 million; Wells, $7.7 million; Priest Rapids, $0.7 million; and Wanapum, $1.0 million.*

[4] *On December 28, 2001, PSE signed a contract offer for new contracts for the Priest Rapids and Wanapum Developments. On April 12, 2002, PSE signed amendments to those agreements which are technical clarifications of certain sections of the agreements. Under the terms of these contracts, PSE will continue to obtain capacity and energy for the term of any new FERC license to be obtained by Grant County PUD. Grant County PUD filed an "Application for New License for the Priest Rapids Project" on October 29, 2003. The new contract terms begin in November of 2005 for the Priest Rapids Development and in November of 2009 for the Wanapum Development. Unlike the current contracts, in the new contracts PSE's share of power from the developments declines over time as Grant County PUD's load increases. On March 8, 2002, the Yakama Nation filed a complaint with FERC which alleged that Grant County PUD's new contracts unreasonably restrain trade and violate various sections of the Federal Power Act and Public Law 83-544. On November 21, 2002, FERC dismissed the complaint while agreeing that certain aspects of the complaint had merit. As a result, it has ordered Grant County PUD to remove specific sections of the contract which constrain the parties to the Grant County PUD contracts from competing with Grant County PUD for a new license. A rehearing has been requested.*

Early in 2003, the Colville Confederated Tribes (Colville Tribe) presented a claim to Douglas County PUD based upon allegedly unpaid past annual charges for the Wells Hydroelectric project for the use of Colville Tribal lands. The Colville Tribe also claimed that annual charges would also be due for periods into the future. On November 1, 2004, Douglas County PUD entered into a settlement with the Colville Tribe concerning claims that the Colville Tribe had asserted against Douglas County PUD for the use by the Wells project of Tribal lands. PSE approved the settlement and participated in the filing Douglas County PUD made on November 23, 2004 seeking FERC approval. The settlement was approved in a FERC order on February 11, 2005. It is unlikely that any party will seek a rehearing of that FERC order, of which the deadline for doing so is March 13, 2005. When the settlement becomes final, the effects on PSE will be through modestly increased power costs, and a small reduction to the amount of power delivered to PSE due to the allocation to the Colville Tribe. The Tribe's allocation will be treated as an encroachment to the project, thus reducing the amount of power available for purchase by others.

The Company's estimated payments for power purchases from the Columbia River are $79.9 million for 2005, $80.1 million for 2006, $83.2 million for 2007, $86.9 million for 2008, $89.7 million in 2009, and in the aggregate, $54.6 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 $79.3 million for 2005, $81.5 million for 2006, $82.9 million for 2007, $83.7 million for 2008, $83.5 million in 2009 and in the aggregate, $349.6 million 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), PSE entered into long-term firm purchased power contracts with non-utility generators. The Company purchases the net electrical output of four 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. The Company's estimated payments under these contracts are $210.2 million for 2005, $215.4 million for 2006, $205.3 million for 2007, $205.3 million for 2008, and $207.1 million for 2009, and in the aggregate, $527.4 million thereafter through 2013.

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

(DOLLARS IN MILLIONS)	2005	2006	2007	2008	2009	2010 & THERE-AFTER	TOTAL
Columbia River Projects	$ 79.9	$ 80.1	$ 83.2	$ 86.9	$ 89.7	$ 54.6	$ 474.4
Other utilities	79.3	81.5	82.9	83.7	83.5	349.6	760.5
Non-utility generators	210.2	215.4	205.3	205.3	207.1	527.4	1,570.7
Total	$ 369.4	$ 377.0	$ 371.4	$ 375.9	$ 380.3	$ 931.6	$ 2,805.6

Total purchased power contracts provided the Company with approximately 9.4 million, 11.0 million and 12.1 million MWh of firm energy at a cost of approximately $404.7 million, $479.2 million and $466.1 million for the years 2004, 2003 and 2002, respectively.

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, 2004:

			COMPANY'S SHARE	
(DOLLARS IN MILLIONS)	ENERGY SOURCE (FUEL)	COMPANY'S OWNERSHIP SHARE	PLANT IN SERVICE AT COST	ACCUMULATED DEPRECIATION
Colstrip Units 1 & 2	Coal	50%	$ 207	$ 134
Colstrip Units 3 & 4	Coal	25%	469	250

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.

As part of its electric operations and in connection with the 1997 restructuring of the Tenaska Power Purchase Agreement, PSE is obligated to deliver to Tenaska up to 48,000 MMBtu per day of natural gas for operation of Tenaska's natural gas-fired 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 United States/Canada border near Sumas, Washington. PSE has entered into a financial arrangement to hedge a portion, 5,000 MMBtu to 10,000 MMBtu per day, of future gas supply costs associated with this obligation. The Company has a maximum financial obligation under this hedge agreement of $18.9 million in 2005 and $2.2 million in 2006.

As part of its electric operations and in connection with the 1999 buyout of the Cabot gas supply contract, PSE is obligated to deliver to Encogen up to 21,800 MMBtu per day of natural gas for operation of the Encogen natural gas-fired cogeneration facility. This obligation continues for the remaining term of the original Cabot agreement. The Company entered into a financial arrangement to hedge a portion of future gas supply costs associated with this obligation, 10,000 MMBtu per day, for the remaining term of the agreement. The Company has a maximum financial obligation under this hedge agreement of $8.7 million in 2005, $9.0 million in 2006, $9.2 million in 2007 and $9.6 million thereafter. Depending on actual market prices, these costs will be partially, or perhaps entirely, offset by floating price payments received under the hedge arrangement. Encogen has two gas supply agreements that comprise 40% of the plant's requirements with remaining terms ranging from less than 1 year to 3.5 years. The obligations under these contracts are $14.1 million in 2005, $2.2 million in 2006, $2.5 million in 2007 and $1.4 million in the aggregate thereafter.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are generally classified as normal purchases and normal sales or in some cases recorded at fair value in accordance with SFAS No. 133 and SFAS No. 149. Commitments under these contracts are $138.2 million in 2005 and $41.2 thereafter.

GAS SUPPLY

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of gas supply for its firm customers. Many of these contracts, which have remaining terms from less than 1 year to 19 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage.

The Company contracts all its long term firm gas service, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation. The Company incurred demand charges in 2004 for firm gas supply, firm transportation service and firm storage and peaking service of $21.4 million, $63.6 million and $5.7 million, respectively. WNG CAP I incurred demand charges in 2004 for firm transportation service of $8.4 million which is included in the total Company demand charges.

The following table summarizes the Company's obligations for future demand charges through the primary terms of its existing contracts. The quantified obligations are based on current contract prices and FERC authorized rates, which are subject to change.

DEMAND CHARGE OBLIGATIONS (DOLLARS IN MILLIONS)	2005	2006	2007	2008	2009	2010 & THERE-AFTER	TOTAL
Firm gas supply	$ 1.8	$ 1.2	$ 1.0	$ 0.8	$ 0.5	$ 1.0	$ 6.3
Firm transportation service	69.6	68.8	65.0	55.6	110.2	117.2	486.4
Firm storage service	11.5	10.5	7.7	7.7	7.7	40.2	85.3
Total	$ 82.9	$ 80.5	$ 73.7	$ 64.1	$ 118.4	$ 158.4	$ 578.0

SERVICE CONTRACT

On August 30, 2001, PSE and Alliance Data Systems Corp. announced a contract under which Alliance Data will provide data processing and billing services for PSE. In providing services to PSE under the 10-year agreement, Alliance Data will use ConsumerLinX software, PSE's customer-information software developed by a former subsidiary, ConneXt. Alliance Data acquired the assets of ConneXt, including the exclusive use of the ConsumerLinX software for five years with an option for renewal. Alliance Data will offer ConsumerLinX as part of its integrated, single-source customer relationship management solution for large-scale, regulated utility clients. The obligations under the contract are $22.2 million in 2005, $22.8 million in 2006, $23.4 million in 2007, $24.0 million in 2008, $24.6 million in 2009 and $42.3 million in the aggregate thereafter.

In April 2004, PSE acquired a 49.85% interest in the Frederickson 1 generating facility. As part of that acquisition, PSE became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas combined cycle unit. The contract was initiated in December 2000, and runs for the earlier of 96,000 factory fired hours or 18 years. The contract requires payments based on both a fixed and variable cost component, depending on how much the facility is used. PSE's share of the estimated obligation under the contract based on projected future use of the facility are $1.1 million in 2005, $1.1 million in 2006, $5.1 million in 2007, $1.8 million in 2008, $1.1 million in 2009, and $12.2 million in the aggregate thereafter.

FREDONIA 3 AND 4 OPERATING LEASE

PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended for this purpose in April 2001. The lease has a term expiring in 2011, but can be canceled by PSE at any time. Payments under the lease vary with changes in the London Interbank Offered Rate (LIBOR). At December 31, 2004, PSE's outstanding balance under the lease was $56.3 million. The expected residual value under the lease is the lesser of $37.4 million or 60% of the cost of the equipment. In the event the equipment is sold to a third party upon termination of the lease and the aggregate sales proceeds are less than the unamortized value of the equipment, PSE would be required to pay the lessor contingent rent in an amount equal to the deficiency up to a maximum of 87% of the unamortized value of the equipment.

SURETY BOND

The Company has a self-insurance surety bond in the amount for $5.9 million guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and nine self-insurer's pension bonds totaling $1.5 million.

ENVIRONMENTAL

The Company is subject to environmental laws and regulations by federal, state and local authorities and has been required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The

Company has also been named by the Environmental Protection Agency, the Washington State Department of Ecology, and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring these sites. 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 insurance companies, from 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, 2004.

ELECTRIC SITES

The Company has expended approximately $20.8 million related to the remediation activities covered by the Washington Commission's order and has accrued approximately $1.7 million as a liability for future remediation costs for these and other remediation activities. To date, the Company has recovered approximately $20.0 million from insurance carriers.

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.

GAS SITES

The Company has expended approximately $69.6 million related to the remediation activities covered by a Washington Commission order and has accrued approximately $30.6 million for future remediation costs for these and other remediation sites. To date, the Company has recovered approximately $60.7 million from insurance carriers and other third parties. The Company expects to recover legal and remediation activities from either insurance companies or customers per Washington Commission orders.

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.

LITIGATION

There are several actions in the U.S. Ninth Circuit Court of Appeals against Bonneville Power Administration (BPA), in which the petitioners assert or may assert that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing, a number of contracts, including the amended settlement agreement regarding the Residential Purchase and Sale Program and the conditional settlement agreements between BPA and PSE which modified the payment provisions of the Residential Purchase and Sale Program. BPA rates used in such amended settlement agreement between BPA and PSE for determining the amounts of money to be paid to PSE as residential exchange benefits during the period October 1, 2001 through September 30, 2006 have been confirmed, approved and allowed to go into effect by FERC. There are also several actions in the U.S. Ninth Circuit Court of Appeals against BPA, in which petitioners assert that BPA acted contrary to law in adopting or implementing the rates or rate adjustment clause upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period are based. It is not clear what impact, if any, review of such rates may have on PSE.

Other contingencies, arising out of the normal course of the Company's business, exist at December 31, 2004. 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 24. *Segment Information*

Puget Energy operates in primarily two business segments: regulated utility operations (PSE), which includes the account receivables securitization program, and construction services (InfrastruX). Puget Energy's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The service territory of PSE covers approximately 6,000 square miles in the State of Washington. InfrastruX specializes in construction services to other gas and electric utilities primarily in the Midwest, Texas, south-central and eastern United States.

One minor non-utility business segment which includes two PSE subsidiaries, and Puget Energy, is described as other. The PSE subsidiaries are a real estate investment and development company and a holding company for a small non-utility wholesale generator. Reconciling items between segments are not significant.

After completing a strategic review of InfrastruX, Puget Energy has decided to exit the utility construction services sector. Puget Energy's Board of Directors approved the decision on February 8, 2005. The decision to exit the business is the result of the Company's need to invest in the core utility business to acquire or construct energy generating resources and energy delivery infrastructure. During 2005, Puget Energy intends to monetize its interest in InfrastruX through sale or third party recapitalization and invest the proceeds in PSE.

2004 (Dollars in Thousands)	Regulated Utility	InfrastruX	Other	Reconciling Item	Puget Energy Total
Revenues	$ 2,192,340	$ 369,936	$ 6,537	--	$ 2,568,813
Depreciation and amortization	228,310	18,276	256	--	246,842
Goodwill impairment	--	91,196	--	--	91,196
Income tax	75,755	(1,793)	1,002	--	74,964
Operating income (loss)	285,258	(70,928)	2,421	--	216,751
Interest charges, net of AFUDC	166,411	6,460	219	--	173,090
Net income (loss)	123,401	(70,388)	2,009	--	55,022
Goodwill, net	--	43,503	--	--	43,503
Total assets	5,511,631	251,097	70,641	--	5,833,369
Construction expenditures - excluding equity AFUDC	393,891	--	--	--	393,891
Additions to other property, plant and equipment	--	15,512	--	--	15,512

2003 (Dollars in Thousands)	Regulated Utility	InfrastruX	Other	Reconciling Item[2]	Puget Energy Total
Revenues[1]	$ 2,034,973	$ 341,787	$ 6,043	--	$ 2,382,803
Depreciation and amortization	219,851	16,779	236	--	236,866
Income tax	69,823	1,594	952	--	72,369
Operating income	295,219	7,452	2,504	--	305,175
Interest charges, net of AFUDC	179,437	5,485	123	--	185,045
Net income	119,144	1,766	438	(5,151)	116,197
Goodwill, net	--	133,302	--	--	133,302
Total assets	5,281,474	342,332	75,196	--	5,699,002
Construction expenditures - excluding equity AFUDC	269,973	--	--	--	269,973
Additions to other property, plant and equipment	--	15,536	--	--	15,536

2002 (Dollars in Thousands)	Regulated Utility	InfrastruX	Other	Reconciling Item[2]	Puget Energy Total
Revenues[1]	$ 1,985,899	$ 319,529	$ 9,753	--	$ 2,315,181
Depreciation and amortization	215,097	13,426	220	--	228,743
Income tax	49,733	6,703	2,824	--	59,260
Operating income	289,511	15,595	4,563	--	309,669
Interest charges, net of AFUDC	190,861	5,516	--	--	196,377
Net income	104,044	9,455	4,384	(7,831)	110,052
Goodwill, net	--	125,555	--	--	125,555
Total assets	5,323,129	319,248	129,756	--	5,772,133
Construction expenditures - excluding equity AFUDC	224,165	--	--	--	224,165
Additions to other property, plant and equipment	--	11,621	--	--	11,621

[1] *Revenues for the Regulated Utility segment were reduced $108.7 million and $77.1 million in 2003 and 2002, respectively as a result of a reclassification from implementing EITF No. 03-11 on January 1, 2004. The reclassification had no effect on financial position or results of operations.*

[2] *Reconciling item is preferred stock dividend accrual at PSE that is treated as an other deduction at Puget Energy.*

SUPPLEMENTAL QUARTERLY FINANCIAL DATA

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.

PUGET ENERGY

(Unaudited; dollars in thousands except per share amounts) 2004 QUARTER	FIRST	SECOND[1]	THIRD	FOURTH[2]
Operating revenues	$ 743,470	$ 515,939	$ 514,951	$ 794,452
Operating income	109,680	35,216	53,825	18,031
Other income	64	1,586	318	2,324
Net income (loss)	66,365	(6,780)	11,124	(15,687)
Basic earnings per common share	$ 0.67	$ (0.07)	$ 0.11	$ (0.16)
Diluted earnings per common share	$ 0.67	$ (0.07)	$ 0.11	$ (0.16)

(Unaudited; dollars in thousands except per share amounts) 2003 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues[3]	$ 640,637	$ 524,060	$ 490,258	$ 727,849
Operating income	91,385	66,407	54,389	92,994
Other income	704	2,247	2,663	(4,050)
Net income before cumulative effect of accounting change	42,889	20,598	9,885	42,993
Net income	42,720	20,598	9,885	42,993
Basic earnings per common share	$ 0.46	$ 0.22	$ 0.10	$ 0.44
Diluted earnings per common share	$ 0.45	$ 0.22	$ 0.10	$ 0.44

(Unaudited; dollars in thousands except per share amounts) 2002 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues[3]	$ 720,997	$ 529,803	$ 442,577	$ 621,804
Operating income	76,571	76,833	57,098	99,168
Other income	384	3,441	230	1,403
Net income	24,466	29,429	6,572	49,585
Basic and diluted earnings per common share	$ 0.28	$ 0.34	$ 0.07	$ 0.55

[1] *The second quarter 2004 includes a disallowance of $36.5 million or $23.7 million after-tax related to a Washington Commission order stating PSE did not prudently manage gas costs for the Tenaska generating facility.*

[2] *The fourth quarter 2004 includes a non-cash goodwill impairment charge of $91.2 million or $76.6 million after-tax and minority interest related to goodwill at InfrastruX.*

[3] *Operating revenues in 2003 and 2002 were revised as a result of a reclassification due to Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gaines and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03," which became effective on January 1, 2004. First, second, third and fourth quarter 2003 revenues were reduced by $35.3 million, $33.8 million, $25.3 million and $14.3 million, respectively. First, second, third and fourth quarter 2002 revenues were reduced by $18.1 million, $11.0 million, $15.9 million and $32.1 million, respectively. The impact of EITF No. 03-11 had no effect on financial position or results of operations.*

PUGET SOUND ENERGY

(Unaudited; dollars in thousands) 2004 QUARTER	FIRST	SECOND[1]	THIRD	FOURTH
Operating revenues	$ 668,714	$ 423,123	$ 415,026	$ 692,012
Operating income	108,845	30,704	50,363	98,330
Other income	68	1,570	356	2,368
Net income (loss)	66,898	(9,540)	9,647	59,187

(Unaudited; dollars in thousands) 2003 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues[2]	$ 569,960	$ 431,717	$ 397,116	$ 642,224
Operating income	93,935	62,120	51,046	90,803
Other income	691	2,309	2,620	(4,033)
Net income before cumulative effect of accounting change	48,270	19,614	9,488	42,683
Net income	48,101	19,614	9,488	42,683

(Unaudited; dollars in thousands) 2002 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues[2]	$ 660,236	$ 453,681	$ 350,204	$ 531,531
Operating income	74,732	72,724	51,367	95,769
Other income	309	3,455	210	1,241
Net income	25,698	28,839	4,701	49,709

[1] *The second quarter 2004 includes a disallowance of $36.5 million or $23.7 million after-tax related to a Washington Commission order stating PSE did not prudently manage gas costs for the Tenaska generating facility.*

[2] *Operating revenues in 2003 and 2002 were revised as a result of a reclassification due to Emerging Issues Task Force Issue No. 03-11, "Reporting Realized Gaines and Losses on Derivative Instruments That Are Subject to FASB No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-03," which became effective on January 1, 2004. First, second, third and fourth quarter 2003 revenues were reduced by $35.3 million, $33.8 million, $25.3 million and $14.3 million, respectively. First, second, third and fourth quarter 2002 revenues were reduced by $18.1 million, $11.0 million, $15.9 million and $32.1 million, respectively. The impact of EITF No. 03-11 had no effect on financial position or results of operations.*

SCHEDULE II

Valuation and Qualifying Accounts and Reserves

PUGET ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2004				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 4,359	$ 7,668	$ 7,507	$ 4,520
Reserve on wholesale sales	41,488	--	--	41,488
Deferred tax asset valuation allowance	--	17,988	--	17,988
Tenaska disallowance reserve	--	36,490	33,334	3,156
YEAR ENDED DECEMBER 31, 2003				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,863	$ 9,387	$ 8,891	$ 4,359
Reserve on wholesale sales	41,488	--	--	41,488
Industrial accident reserve	2,000	--	2,000	--
Gas transportation contracts reserve	139	--	139	--
YEAR ENDED DECEMBER 31, 2002				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 5,488	$ 11,191	$ 12,816	$ 3,863
Reserve on wholesale sales	41,488	--	--	41,488
Industrial accident reserve	--	4,000	2,000	2,000
Gas transportation contracts reserve	139	--	--	139

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS CHARGED TO COSTS AND EXPENSES	DEDUCTIONS	BALANCE AT END OF PERIOD
YEAR ENDED DECEMBER 31, 2004				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,484	$ 7,343	$ 7,157	$ 2,670
Reserve on wholesale sales	41,488	--	--	41,488
Tenaska disallowance reserve	--	36,490	33,334	3,156
YEAR ENDED DECEMBER 31, 2003				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 1,990	$ 9,385	$ 8,891	$ 2,484
Reserve on wholesale sales	41,488	--	--	41,488
Industrial accident reserve	2,000	--	2,000	--
Gas transportation contracts reserve	139	--	139	--
YEAR ENDED DECEMBER 31, 2002				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,666	$ 11,140	$ 12,816	$ 1,990
Reserve on wholesale sales	41,488	--	--	41,488
Industrial accident reserve	--	4,000	2,000	2,000
Gas transportation contracts reserve	139	--	--	139

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

PUGET ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of Puget Energy's management, including the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Energy has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2004, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial officer of Puget Energy concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in Puget Energy's internal control over financial reporting during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, Puget Energy's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Puget Energy's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of Puget Energy's President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organization of the Treadway Commission. Based on the assessment, Puget Energy's management concluded that its internal control over financial reporting was effective as of December 31, 2004.

Puget Energy's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

PUGET SOUND ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of December 31, 2004, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial officer of PSE concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in PSE's internal control over financial reporting during the quarter ended December 31, 2004, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

PSE's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Under the supervision and with the participation of PSE's President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Sound Energy's management assessed the effectiveness of internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organization of the Treadway Commission. Based on the assessment, PSE's management concluded that its internal control over financial reporting was effective as of December 31, 2004.

PSE's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

PUGET ENERGY

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Available Information" in Part I of this report and "Proposal 1 - Election of Directors," "Directors Continuing in Office," "Other Director Information," "Board of Directors and Corporate Governance" and "Security Ownership of Directors and Executive Officers--Section 16(a) Beneficial Ownership Reporting Compliance" in Puget Energy's proxy statement for its 2005 Annual Meeting of Shareholders (Commission file No. 1-16305). Reference is also made to the information regarding Puget Energy's executive officers set forth in Part I of this report.

PUGET SOUND ENERGY

The information called for by Item 10 with respect to PSE is omitted pursuant to General Instruction I(2)(c) to Form 10-K (omission of information by certain wholly owned subsidiaries).

ITEM 11. EXECUTIVE COMPENSATION

PUGET ENERGY

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Director Compensation," "Executive Compensation" and "Employment Contracts, Termination of Employment and Change-In-Control Arrangements" in Puget Energy's proxy statement for its 2005 Annual Meeting of Shareholders (Commission File No. 1-16305).

PUGET SOUND ENERGY

The information called for by Item 11 with respect to PSE is omitted pursuant to General Instruction I(2)(c) to Form 10-K (omission of information by certain wholly owned subsidiaries).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

PUGET ENERGY

EQUITY COMPENSATION PLAN INFORMATION

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Equity Compensation Plan Information" in Puget Energy's proxy statement for its 2005 Annual Meeting of Shareholders (Commission File No. 1-16305).

BENEFICIAL OWNERSHIP

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Security Ownership of Directors and Executive Officers" in Puget Energy's proxy statement for its 2005 Annual Meeting of Shareholders (Commission File No. 1-16305).

PUGET SOUND ENERGY

EQUITY COMPENSATION PLAN INFORMATION

The information called for by this item with respect to PSE is omitted pursuant to General Instruction I(2)(e) to Form 10-K (omission of information by wholly owned subsidiaries).

BENEFICIAL OWNERSHIP

As of December 31, 2004, all of the issued and outstanding shares of PSE's common stock were held beneficially and of record by Puget Energy.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The aggregate fees billed by PricewaterhouseCoopers LLP, the Company's independent registered public accounting firm, for the year ended December 31 were as follows:

	2004		2003	
(DOLLARS IN THOUSANDS)	PUGET ENERGY	PSE	PUGET ENERGY	PSE
Audit fees[1]	$ 2,084	$ 1,695	$ 850	$ 453
Audit related fees[2]	82	82	261	147
Tax fees[3]	59	55	200	168
Total	$ 2,225	$ 1,832	$ 1,311	$ 768

1 *For professional services rendered for the audit of Puget Energy's and PSE's annual financial statements, reviews of financial statements included in the Companies' Forms 10-Q, and consents and reviews of documents filed with the Securities and Exchange Commission. The 2004 fees are estimated and include an aggregate amount of $1,251,000 and $1,156,000 billed to Puget Energy and PSE, respectively through December 31, 2004. The 2003 fees include an aggregate amount of approximately $444,000 and $277,000 billed to Puget Energy and PSE, respectively, through December 31, 2003. In 2004, audit fees included $1,284,000 and $1,120,000 for professional services rendered for the audits of Puget Energy's and PSE's assessment of, and the effectiveness of, internal controls over financial reporting (Sarbanes-Oxley 404).*

2 *Consists of employee benefit plan audits, due diligence reviews and assistance with Sarbanes-Oxley readiness.*

3 *Consists of tax planning, consulting and tax return reviews.*

The Audit Committees of the Company have adopted policies for the pre-approval of all audit and non-audit services provided by the Company's independent auditor. The policies are designed to ensure that the provision of these services does not impair the auditor's independence. Under the policies, unless a type of service to be provided by the independent auditor has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee.

The annual audit services engagement terms and fees, as well as any changes in terms, conditions and fees relating to the engagement, are subject to specific pre-approval by the Audit Committees. In addition, on an annual basis, the Audit Committees grant general pre-approval for specific categories of audit, audit-related, tax and other services, within specified fee levels, that may be provided by the independent auditor. With respect to each proposed pre-approved service, the independent auditor is required to provide detailed back-up documentation to the Audit Committees regarding the specific services to be provided. Under the policies, the Audit Committees may delegate pre-approval authority to one or more of their members. The member or members to whom such authority is delegated shall report any responsibilities to pre-approve services performed by the independent auditor to management.

For 2004 all audit and non-audit services were pre-approved.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a) Documents filed as part of this report:
   1) *Financial Statements.* See index on page 66.
   2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 123, as required for the years ended December 31, 2004, 2003 and 2002, consist of the following:

      II. Valuation of Qualifying Accounts

   3) Exhibits - see index on page 129.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUGET ENERGY, INC.

/s/ Stephen P. Reynolds
Stephen P. Reynolds
President and Chief Executive Officer

Date: March 1, 2005

PUGET SOUND ENERGY

/s/ Stephen P. Reynolds
Stephen P. Reynolds
President and Chief Executive Officer

Date: March 1, 2005

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

SIGNATURE	TITLE	DATE
	(Puget Energy and PSE unless otherwise noted)	
/s/ Douglas P. Beighle (Douglas P. Beighle)	Chairman of the Board	March 1, 2005
/s/ Stephen P. Reynolds (Stephen P. Reynolds)	President, Chief Executive Officer and Director	
/s/ Bertrand A. Valdman (Bertrand A. Valdman)	Senior Vice President Finance and Chief Financial Officer	
/s/ James W. Eldredge (James W. Eldredge)	Corporate Secretary and Chief Accounting Officer	
/s/ William S. Ayer (William S. Ayer)	Director	
/s/ Charles W. Bingham (Charles W. Bingham)	Director	
/s/ Phyllis J. Campbell (Phyllis J. Campbell)	Director	
/s/ Craig W. Cole (Craig W. Cole)	Director	
/s/ Robert L. Dryden (Robert L. Dryden)	Director	
/s/ Stephen E. Frank (Stephen E. Frank)	Director	
/s/ Tomio Moriguchi (Tomio Moriguchi)	Director	
/s/ Dr. Kenneth P. Mortimer (Dr. Kenneth P. Mortimer)	Director	
/s/ Sally G. Narodick (Sally G. Narodick)	Director	

EXHIBIT INDEX

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

3(i).1	Restated Articles of Incorporation of Puget Energy (Incorporated by reference to Exhibit 99.2, Puget Energy's Current Report on Form 8-K filed January 2, 2001, Commission File No. 333-77491).
3(i).2	Restated Articles of Incorporation of PSE (included as Annex F to the Joint Proxy Statement/Prospectus filed February 1, 1996, Registration No. 333-617).
3(ii).1	Amended and Restated Bylaws of Puget Energy dated March 7, 2003 (Exhibit 3(ii).1 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).
3(ii).2	Amended and Restated Bylaws of PSE dated March 7, 2003 (Exhibit 3(ii).2 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).
4.1	Fortieth through Seventy-ninth Supplemental Indentures defining the rights of the holders of PSE'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)-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; Exhibit 4.27 to Current Report on Form 8-K dated March 5, 1999; Exhibit 4.2 to Current Report on form 8-K dated November 2, 2000; and Exhibit 4.2 to Current Report on Form 8-K dated June 3, 2003).
4.2	Indenture defining the rights of the holders of PSE's senior notes (incorporated herein by reference to Exhibit 4-a to PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
4.3	First Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series A (incorporated herein by reference to Exhibit 4-b to PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1998, Commission File No. 1-4393).
4.4	Second Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series B (incorporated herein by reference to Exhibit 4.6 to PSE's Current Report on Form 8-K, dated March 5, 1999, Commission File No. 1-4393).
4.5	Third Supplemental Indenture defining the rights of the holders of PSE's senior notes, Series C (incorporated herein by reference to Exhibit 4.1 to PSE's Current Report on Form 8-K, dated November 2, 2000, Commission File No. 1-4393).
4.6	Fourth Supplemental Indenture defining the rights of the holders of PSE's senior notes (incorporated herein by reference to Exhibit 4.1 to PSE's Current Report on Form 8-K, dated June 3, 2003, Commission File No. 1-4393).
4.7	Rights Agreement dated as of December 21, 2000 between Puget Energy and Mellon Investor Services LLC, as Rights Agent (incorporated herein by reference to Exhibit 2.1 to PSE's Registration Statement on Form 8-A, dated January 2, 2001, Commission File No. 1-16305).
4.8	Indenture between PSE and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.1 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).
4.9	Amended and Restated Declaration of Trust between Puget Sound Energy Capital Trust and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.2 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).
4.10	Series A Capital Securities Guarantee Agreement between PSE and the First National Bank of Chicago dated June 6, 1997 (incorporated herein by reference to Exhibit 4.3 of PSE's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997, Commission File No. 1-4393).
4.11	First Supplemental Indenture dated as of October 1, 1959 (Exhibit 4-D to Registration No. 2-17876).
4.12	Sixth Supplemental Indenture dated as of August 1, 1966 (Exhibit to Form 8-K for month of August 1966, File No. 0-951).
4.13	Seventh Supplemental Indenture dated as of February 1, 1967 (Exhibit 4-M, Registration No. 2-27038).
4.14	Sixteenth Supplemental Indenture dated as of June 1, 1977 (Exhibit 6-05 to Registration No. 2-60352).

4.15 Seventeenth Supplemental Indenture dated as of August 9, 1978 (Exhibit 5-K.18 to Registration No. 2-64428).

4.16 Twenty-second Supplemental Indenture dated as of July 15, 1986 (Exhibit 4-B.20 to Form 10-K for the year ended September 30, 1986, File No. 0-951).

4.17 Twenty-seventh Supplemental Indenture dated as of September 1, 1990 (Exhibit 4-B.20, Form 10-K for the year ended September 30, 1998, File No. 10-951).

4.18 Twenty-eighth Supplemental Indenture dated as of July 31, 1991 (Exhibit 4-A, Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).

4.19 Twenty-ninth Supplemental Indenture dated as of June 1, 1993 (Exhibit 4-A to Registration No. 33-49599).

4.20 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).

4.21 Thirty-first Supplemental Indenture dated February 10, 1997 (Exhibit 4.30 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-6305 and 1-4393).

4.22 Unsecured Debt Indenture between Puget Sound Energy and Bank One Trust Company, N.A. dated as of May 18, 2001, defining the rights of the holders of Puget Sound Energy's unsecured debentures (incorporated herein by reference to Exhibit 4.3 to Puget Sound Energy's Current Report on Form 8-K, filed May 22, 2001, Commission File No. 1-4393).

4.23 First Supplemental Indenture to the Unsecured Debt Indenture dated as of May 18, 2001 defining the rights of 8.40% Subordinated Deferrable Interest Debentures due June 30, 2041 (incorporated herein by reference to Exhibit 4.4 to Puget Sound Energy's Current Report on Form 8-K, filed May 22, 2001, Commission File No. 1-4393).

4.24 Amended and Restated Declaration of Trust of Puget Sound Energy Trust II dated as of May 18, 2001 (incorporated herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, filed May 22, 2001, Commission File No. 1-4393).

4.25 Preferred Securities Guarantee Agreement, dated May 18, 2001 between Puget Sound Energy and Bank One Trust Company, N.A. for the benefit of the holders of the trust preferred securities of the Puget Sound Energy Trust II (incorporated herein by reference to Exhibit 4.5 to Puget Sound Energy's Current Report on Form 8-K, filed May 22, 2001, Commission File No. 1-4393).

4.26 Pledge Agreement dated March 11, 2003 between Puget Sound Energy and Wells Fargo Bank Northwest, National Association, as Trustee (incorporated herein by reference to Exhibit 4.24 to the Company's Post-Effective Amendment No. 1 to Registration Statement on Form S-3 dated July 11, 2003, Commission File No. 333-82940-02).

4.27 Loan Agreement dated as of March 1, 2003, between the City of Forsyth, Rosebud County, Montana and Puget Sound Energy (incorporated herein by reference to Exhibit 4.25 to the Company's Post-Effective Amendment No. 1 to Registration Statement on Form S-3, dated July 11, 2003, Commission File No. 333-82490-02).

* 4.28 Eightieth Supplemental Indenture dated as of April 30, 2004 defining the rights of the holders of PSE's First Mortgage Bonds.

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

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

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

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

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

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

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

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

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

10.10 Construction and Ownership Agreement dated as of July 30, 1971 between The Montana Power Company and PSE (Exhibit 5-b to Registration No. 2-45702).

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

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

10.13 Transmission Agreement dated April 17, 1981 between the Bonneville Power Administration and PSE (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).

10.14 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).

10.15 Ownership and Operation Agreement dated as of May 6, 1981 between PSE 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).

10.16 Colstrip Project Transmission Agreement dated as of May 6, 1981 between PSE 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).

10.17 Common Facilities Agreement dated as of May 6, 1981 between PSE 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).

10.18 Amendment dated as of June 1, 1968, to Power Sales Contract between Public Utility District No. 1 of Chelan County, Washington and PSE (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).

10.19 Transmission Agreement dated as of December 30, 1987 between the Bonneville Power Administration and PSE (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).

10.20 Power Sales Agreement between Northwestern Resources (formerly The Montana Power Company) and PSE 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).

10.21 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 , PacifiCorp and PSE (Exhibit (10)-91 to Annual Report on Form 10-K for the fiscal year ended December 31, 1990, Commission File No. 1-4393).

10.22 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 PSE (Exhibit (10)-4 to Quarterly Report on Form 10-Q for the quarter ended March 31, 1991, Commission File No. 1-4393).

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

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

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

10.26 General Transmission Agreement dated as of December 1, 1994 between the Bonneville Power Administration and PSE (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).

10.27 PNW AC Intertie Capacity Ownership Agreement dated as of October 11, 1994 between the Bonneville Power Administration and PSE (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).

10.28 Amendment to Gas Transportation Service Contract dated July 31, 1991 between Washington Natural Gas Company and Northwest Pipeline Corporation (Exhibit 10-E.2 to Form 10-K for the year ended September 30, 1995, File No. 11271).

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

10.30 Puget Energy, Inc. Non-employee Director Stock Plan. (incorporated herein by reference to Exhibit 99.1 to Puget Energy's Post Effective Amendment No. 1 to Form S-8 Registration Statement, dated January 2, 2001, Commission File No. 333-41157-99.)

** 10.31 Amendment No. 1 to the Puget Energy, Inc. Non-employee Director Stock Plan, effective as of January 1, 2003 (Exhibit 10.94 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).

** 10.32 Puget Energy, Inc. Employee Stock Purchase Plan. (Incorporated herein by reference to Exhibit 99.1 to Puget Energy's Post Effective Amendment No. 1 to Form S-8 Registration Statement, dated January 2, 2001, Commission File No. 333-41113-99.)

** 10.33 1995 Long-Term Incentive Compensation Plan. (Exhibit 10.108 to Annual Report on Form 10-K for the fiscal year ended December 31, 2000, Commission File No. 1-4393 and 1-16305).

** 10.34 1995 Long-Term Incentive Compensation Plan (Incorporated herein by reference to Exhibit 99.1 to Puget Energy's Post Effective Amendment No. 1 to Form S-8 Registration Statement, dated January 2, 2001, Commission File No. 333-61851-99.)

** 10.35 Employment agreement with S. P. Reynolds, Chief Executive Officer and President dated January 7, 2002 (Exhibit 10.104 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2001, Commission File No. 1-16305 and 1-4393).

10.36 Credit Agreement dated May 27, 2004, among InfrastruX Group, Inc. and various Banks named therein, Union Bank of California as administrative agent. (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 2004, Commission File No. 1-4393 and 1-16305).

10.37 Power Sales Contract dated April 15, 2002, between Public Utility District No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-1 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.38 Reasonable Portion Power Sales Contract dated April 15, 2002, between Public Utility District No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-2 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.39 Additional Power Sales Contract dated April 15, 2002, between Public Utility district No. 2 of Grant County, Washington, and PSE, relating to the Priest Rapids Project. (Exhibit 10-3 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.40 Credit Agreement dated May 27, 2004, covering PSE and various banks named therein, Union Bank of California as administrative agent. (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2004, Commission File No. 1-4393 and 1-16305).

10.41 Receivable Purchase Agreement dated December 23, 2002, among PSE, Rainier Receivables, Inc., and Bank One, NA as agent (Exhibit 10.107 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).

10.42 Receivable Sale Agreement dated December 23, 2002, among PSE and Rainier Receivables, Inc.

** 10.43 Employment agreement with J.M. Ryan, Vice President Energy Portfolio Management, dated November 30, 2001 (Exhibit 10.109 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).

** 10.44 Change-in-Control Agreement with J.M. Ryan, Vice President, Energy Portfolio Management, dated November 30, 2001 (Exhibit 10.110 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).

** 10.45 Change-in-Control Agreement with B. A. Valdman, Senior Vice President, Finance and Chief Financial Officer, dated November 28, 2003 (Exhibit 10.86 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).

** 10.46 Change-in-Control Agreement with S. McLain, Senior Vice President, Operations, dated March 12, 1999. (Exhibit 10.87 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-16305 and 1-4393).

** 10.47 Employment Agreement with M. T. Lennon, President and Chief Executive Officer of InfrastruX, dated May 6, 2002 (Exhibit 10.88 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).

** 10.48	Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President dated, January 8, 2004 (Exhibit 10.90 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).
** 10.49	Restricted Stock Unit Award Agreement with S. P. Reynolds, Chief Executive Officer and President dated, January 8, 2004 (Exhibit 10.91 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).
** 10.50	Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President dated, January 8, 2002 (Exhibit 99.1 to Form S-8 Registration Statement, dated January 8, 2002, Commission File No. 333-76424).
** 10.51	Nonregulated Stock Option Grant Notice/Agreement with S. P. Reynolds, Chief Executive Officer and President dated March 11, 2002 (Exhibit 99.1 and Exhibit 99.2 to Form S-8 Registration Statement dated March 18, 2002, Commission File No. 333-84426).
* 10.52	Change-in-Control Agreement with E. M. Markell, Vice President Corporate Development, dated May 7, 2003.
* 10.53	InfrastruX 2000 Stock Incentive Plan adopted January 26, 2001.
* 10.54	InfrastruX 2000 Stock Incentive Plan Stock Option Grant Notice adopted January 26, 2001.
* 10.55	Puget Sound Energy Amended and Restated Supplemental Executive Retirement Plan for Senior Management dated October 5, 2004.
* 10.56	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Key Employees dated January 1, 2003.
* 10.57	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Nonemployee Directors dated October 1, 2000.
** 10.58	Summary of Director Compensation (incorporated by reference to Exhibit 99.1 to Current Report on Form 8-K, filed February 2, 2005, Commission File Nos. 1-4393 and 1-16305).
* 12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy (2000 through 2004).
* 12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy (2000 through 2004).
* 21.1	Subsidiaries of Puget Energy.
* 21.2	Subsidiaries of PSE.
* 23.1	Consent of PricewaterhouseCoopers LLP.
* 31.1	Certification of Puget Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 31.2	Certification of Puget Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.
* 31.3	Certification of Puget Sound Energy - Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 31.4	Certification of Puget Sound Energy – Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.
* 32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Stephen P. Reynolds.
* 32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Bertrand A. Valdman.

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* *Filed herewith.*

** *Management contract or compensating plan or arrangement.*