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, 2005
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, zip code 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)

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Puget Energy, Inc.	Yes	/X/	No	/ /	Puget Sound Energy, Inc.	Yes	/ /	No /X/

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Puget Energy, Inc.	Yes	/ /	No	/X/	Puget Sound Energy, Inc.	Yes	/ /	No /X/

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.

Puget Energy, Inc.	Yes	/X/	No	/ /	Puget Sound Energy, Inc.	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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Puget Energy, Inc.	Large accelerated filer	/X/	Accelerated filer	/ /	Non-accelerated filer	/ /
Puget Sound Energy, Inc.	Large accelerated filer	/ /	Accelerated filer	/ /	Non-accelerated filer	/X/

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2)

Puget Energy, Inc.	Yes	/ /	No	/X/	Puget Sound Energy, Inc.	Yes	/ /	No /X/

The aggregate market value of the voting stock held by non-affiliates of Puget Energy, Inc., computed by reference to the price at which the common stock was last sold, as of the last business day of Puget Energy's most recently completed second fiscal quarter was approximately $2,339,226,700. The number of shares of Puget Energy, Inc.'s common stock outstanding at February 21, 2006 was 115,891,281 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 2006 Annual Meeting of Shareholders to be filed with the Commission pursuant to Regulation 14A not later than 120 days after December 31, 2005 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
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
InfrastruX	InfrastruX Group, Inc.
kW	Kilowatt (one kilowatt equals one thousand watts)
kWh	Kilowatt Hour (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	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
NOPR	Notice of Proposed Rulemaking
NYSE	New York Stock Exchange
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
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.
PUHCA	Public Utility Holding Company Act
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," "future," "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.

Some important factors that could cause actual results to differ materially from those suggested by the forward-looking statements include those described below in this Form 10-K and the following:

- 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, cost recovery, 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;
- Natural disasters, such as hurricanes, which can cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials;
- Commodity price risks associated with procuring natural gas and power in wholesale markets that impact customer loads;
- 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, negatively affect wholesale energy prices and/or impede PSE's ability to manage its energy portfolio risks and procure energy supply, affect the availability and access to capital and credit markets and/or impact delivery of energy to PSE from its suppliers;
- The effect of wholesale market structures (including, but not limited to, regional market designs or transmission organizations) or other related federal initiatives;
- PSE electric or gas distribution system failure, which may impact PSE's ability to deliver energy supply to its customers;
- Weather, which can have a potentially serious impact on PSE's revenues and/or impact 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 with respect to repair costs, added costs to replace energy or higher costs associated with dispatching a more expensive resource;
- The ability of gas or electric plant to operate as intended;
- 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 affect 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 amount of collection, if any, of PSE's receivables from the 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;
- The loss of significant customers or changes in the business of significant customers, which may result in changes

in demand for PSE's services;

- The impact of acts of terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital or interest rate fluctuations;
- The impacts of natural disasters such as earthquakes, hurricanes, floods, fires or landslides;
- 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; and
- The ability to maintain effective internal controls over financial reporting.

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. You are also advised to consult quarterly reports on Form 10-Q and current reports on Form 8-K, as well as Item 1A-"Risk Factors" of this Form 10-K.

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. Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. InfrastruX is thus treated as a discontinued operation. Puget Energy intends to monetize its interest in InfrastruX through a sale. Puget Energy's ability to complete the sale of InfrastruX to a third party on reasonable terms is subject to a number of factors beyond the Company's control. Puget Energy and PSE are collectively referred to herein as "the Company." The following table provides the percentages of Puget Energy's consolidated continuing operating revenues and net income generated and assets held by the operating segments:

Segment	Percent of Revenue			Percent of Net Income			Percent of Assets		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Puget Sound Energy[1]	99.7%	99.7%	99.7%	91.7%	224.2%	98.1%	94.8%	94.2%	92.7%
InfrastruX[2]	0%	0%	0%	6.1%	(127.8)%	1.5%	4.2%	4.6%	6.0%
Other subsidiaries	0.3%	0.3%	0.3%	2.2%	3.6%	0.4%	1.0%	1.2%	1.3%

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

[2] *In 2005, InfrastruX is presented on a discontinued operations basis and therefore does not present operating revenue. All prior years' operating revenue has been reclassified as discontinued operations.*

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. Puget Energy intends to continue to focus on PSE, its core electric and natural gas transmission and distribution utility business, offering reliable electric and gas service in a cost effective manner to PSE's customers.

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 power purchase agreements to meet load requirements and ensure stable cost-based energy supply within its service territory. During 2005, PSE placed its first wind farm into service and began construction on an additional wind farm. At the end of 2005, PSE requested proposals for new power supply resources. As these proposals are submitted in 2006, PSE will be evaluating the proposals that help to meet the needs of its customers.

Provide a reasonable and attractive return to Puget Energy shareholders. Puget Energy shareholder returns will be the result of growing earnings of PSE through timely cost recovery of ratebase additions, primarily from generating and delivery resources. In addition, Puget Energy is committed to exiting the utility construction services sector, a decision approved by Puget Energy's Board of Directors on February 8, 2005. The decision to exit the business is the result of the Company's decision to focus on and invest in the core utility business to acquire or construct energy generating resources and energy delivery infrastructure. Puget Energy intends to monetize its interest in InfrastruX through a sale.

Be a great corporate citizen. Customers, key constituents and communities expect high quality service and leadership from the Company through energy efficiency, corporate giving and employee involvement. The Company is committed to these initiatives and strives to enhance the quality of life in the region.
Puget Sound Energy, Inc.

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, 2005, PSE had approximately 1,018,100 electric customers, consisting of 901,400 residential, 110,500 commercial, 3,700 industrial and 2,500 other customers; and approximately 693,500 gas customers, consisting of 639,800 residential, 51,000 commercial, 2,600 industrial and 100 transportation customers. At December 31, 2005, approximately 342,200 customers purchased both electricity and gas from PSE. For 2005, PSE added approximately 16,400 electric customers and approximately 21,000 gas customers, representing annualized customer growth rates of 1.6% and 3.1%, respectively. During 2005, PSE's billed retail and transportation revenues from electric utility operations were derived 48% from residential customers, 44% from commercial customers, 7% from industrial customers and 1% from other customers. PSE's retail revenues from gas utility operations were derived 64% from residential customers, 31% from commercial customers and 5% from industrial customers in 2005. 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, 2005, PSE's gross electric utility plant additions were $1.0 billion and retirements were $270 million. In the same five-year period ended December 31, 2005, PSE's gross gas utility plant additions were $620 million and retirements were $86 million. In the same five-year period, PSE's gross common utility plant additions were $129 million and retirements were $41 million. Gross electric utility plant at December 31, 2005 was approximately $4.8 billion, which consisted of 58% distribution, 28% generation, 6% transmission and 8% general plant and other. Gross gas utility plant as of December 31, 2005 was approximately $2.0 billion, which consisted of 86% distribution, 7% transmission and 7% general plant and other. Gross common utility general and intangible plant at December 31, 2005 was approximately $440 million.

INFRASTRUX GROUP, INC.

InfrastruX is a non-regulated construction services business, incorporated in the state of Washington in 2000. InfrastruX provides infrastructure construction services to the electric and gas utility industries primarily in the Midwest, Texas, south-central and eastern United States.

Following a strategic review of InfrastruX conducted by Puget Energy, Puget Energy's Board of Directors decided to exit the utility construction services sector on February 8, 2005. Puget Energy intends to monetize its interest in InfrastruX through a sale. The planned disposal of InfrastruX meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements in 2005. Puget Energy has retained an investment banking firm to assist in the sale of InfrastruX. To date, Puget Energy has not entered into a definitive agreement that would result in the sale of its investment in InfrastruX.

EMPLOYEES

At February 23, 2006, Puget Energy and its subsidiaries had approximately 5,300 full-time employees:

Puget Sound Energy	2,300
InfrastruX	3,000
Total Puget Energy	5,300

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 March 31, 2007 and September 30, 2006, respectively. Discussions on replacement contracts with both unions have commenced. The majority of InfrastruX employees are not represented by unions.

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.pugetenergy.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (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;
- Charters of Board Committees; 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 four business days.

NEW YORK STOCK EXCHANGE CERTIFICATION

On May 19, 2005, 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 Utilities and Transportation Commission (Washington Commission) as to retail utility rates, accounting, the issuance of securities and certain other matters and (2) Federal Energy Regulatory Commission (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

PCA Mechanism. On June 20, 2002, the Washington Commission approved a 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 an electric 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 will be 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 transmission 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 current 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	JULY-DECEMBER 2006 POWER COST VARIABILITY[1]	CUSTOMERS' SHARE	COMPANY'S SHARE [2]
+/- $20 million	+/- $10 million	0%	100%
+/- $20 - $40 million	+/- $10 - $20 million	50%	50%
+/- $40 - $120 million	+/- $20 - $60 million	90%	10%
+/- $120 million	+/- $60 million	95%	5%

[1] *In October 2005, the Washington Commission in its Power Cost Only Rate Case order made a provision to reduce the power cost variability amounts to half the annual power cost variability for the period July 1, 2006 through December 31, 2006.*

[2] *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, on the graduated scale without a cumulative cap.*

Based on past activity under the PCA mechanism and volatility of power costs, it is possible that PSE could experience higher expenses associated with excess power costs based on the sharing arrangement once the cumulative $40 million cap expires on June 30, 2006. As such, the risk dynamics change for PSE and its customers. On October 20, 2005, the Washington Commission approved an amendment to the PCA mechanism changing the PCA period to a calendar year beginning January 1, 2007. The Washington Commission also made provision to reduce the graduated scale to half the annual excess power costs for the period July 1, 2006 through December 31, 2006 without a cap on excess power costs. In addition, the Washington Commission order requires PSE to update the power cost baseline rate accepted in the 2005 Power Cost Only Rate Case (PCORC) proceeding by filing a tariff change to the power cost rate during May 2006 which would be effective July 1, 2006.

Power Cost Only Rate Case. In the June 20, 2002 Washington Commission order, a limited-scope proceeding called a PCORC was created 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 agreed to an expedited five-month PCORC 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 related to 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. On April 7, 2004, the Washington Commission issued an order granting approval for PSE's acquisition of the Frederickson 1 electric generating facility and its cost recovery in PSE's electric rates, and on May 13, 2004 approved an increase of 3.2% or $44.1 million annually.

On October 20, 2005, the Washington Commission approved an increase of 3.7% or $55.6 million annually. The PCORC increase allowed PSE to recover higher projected costs of power effective November 1, 2005. Included in the increase is the recovery of capital and operating costs of the newly acquired Hopkins Ridge wind project. The Hopkins Ridge wind generating facility was completed on November 27, 2005. As a wind generating facility, Hopkins Ridge is eligible for federal Production Tax Credits (PTCs) that will ultimately offset some of the costs associated with generating power from Hopkins Ridge. The PTC is a tax credit provided by the Federal government for generating electricity from certain renewable resources. The current amount of the tax credit is 1.9 cents per kilowatt-hour for wind generation and may be subject to inflation adjustments over time. The tax credit can be claimed for 10 years for a new wind project put into service prior to January 1, 2008. The use of the credit is restricted in that it can only be used to offset 25% of current taxes payable. However, unused credits can be carried forward for up to 20 years.

In the Washington Commission's October 2005 order, a new tariff schedule was approved which provides for the pass through to ratepayers of all benefits of the PTC's for the Hopkins Ridge project. This PTC Tracker will pass through to the customer the actual production tax credits of the Hopkins Ridge project as they are generated. The tracker would not be subject to the sharing bands in the PCA. A deferred tax asset is created for the PTCs that have been generated but have not been used for the current year's tax credit. The credits passed through to the customer will be adjusted by the carrying costs for this deferred tax asset account. Since the customer is receiving the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized, the Company is reimbursed its carrying costs for funds through this calculation.

The October 2005 order authorized the creation of a regulatory asset account that includes the accumulation of the interest on the average monthly cumulative balance of the deferred tax asset account. This regulatory asset account is related to the federal income tax benefits of Hopkins Ridge and is outside the scope of the PCA mechanism. The accounting for this regulatory asset would not be part of any PCA calculation, but would be included in the PTC Tracker calculation.

The Washington Commission also approved an amendment to the PCA mechanism by changing the annual PCA reporting periods to a calendar year period beginning January 1, 2007 with provisions made to reduce the sharing bands in half for the period July 1, 2006 through December 31, 2006. The order also requires PSE to update the power cost baseline rate in the PCA mechanism by filing a tariff change to the power cost rate during May 2006, to be effective July 1, 2006. Finally, the order required PSE to file a general rate case by mid-February 2006 so that a new power cost baseline rate will be effective on January 1, 2007. PSE filed its general rate case on February 15, 2006 and requested to increase electric rates by 9.2% or $148.8 million annually. The Company is proposing in this filing that the annual PCA sharing bands be revised to the following:

Power Cost Variability	Customers' Share	Company's Share
+/- $0 - $25 million	50%	50%
+/- $25 - $120 million	90%	10%
+/- $120 million	95%	5%

In addition to the change in sharing bands for the PCA, the Company is requesting the Washington Commission approve a new tracker mechanism that would allow the Company to recover increased depreciation expense associated with new plant investment incurred between rate filings. The electric depreciation tracker is 0.5%, or $7.9 million, of the rate increase over current rate levels.

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 accumulated costs under the PCA mechanism for these excess costs. The order also 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.

In August 2004, PSE filed the PCA 2 period compliance 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 $6.0 million related to the period July 1, 2003 through December 31, 2003.

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. Due to fluctuations in forward market prices of gas, the amount and timing of any potential disallowance related to Tenaska can change significantly day to day. The projected costs and projected benchmark costs for Tenaska as of December 31, 2005, based on current forward market gas prices are as follows:

(DOLLARS IN MILLIONS)	2006	2007	2008	2009	2010	2011
Projected Tenaska costs *	$ 258.0	$ 258.4	$ 240.5	$ 227.4	$ 214.6	$ 206.8
Projected Tenaska benchmark costs	175.3	174.8	182.9	189.9	197.4	205.6
Over (under) benchmark costs	$ 82.7	$ 83.6	$ 57.6	$ 37.5	$ 17.2	$ 1.2
Projected 50% disallowance based on Washington Commission methodology	$ 8.8	$ 7.7	$ 6.4	$ 4.8	$ 3.0	$ 0.6

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

General Tariff. On February 18, 2005, the Washington Commission approved a 4.1% general tariff electric rate case increase to recover higher costs of providing electric service to customers. The rate increase was intended to 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%.

On February 15, 2006, PSE filed a request with the Washington Commission to increase electric rates by 9.2% or $148.8 million annually and to approve a depreciation tracker mechanism. The resolution of the general rate case may be up to an 11-month process from the time the general rate case is filed.

Accounting Orders. During 2002, PSE changed its tax accounting method with respect to capitalized internal labor and overheads, which permitted the Company to immediately deduct certain costs that it had previously capitalized. On August 2, 2005, the Internal Revenue Service and the Treasury Department issued Revenue Ruling 2005-53 and the related Regulations. The Revenue Ruling and the Regulations will require utility companies, including PSE, to adopt a less advantageous method of accounting and to repay the accumulated tax benefits. Through September 30, 2005, the Company claimed $66.3 million in accumulated tax benefits. PSE accounted for the accumulated tax benefits as temporary differences in determining its deferred income tax balances. Consequently, the repayment of the tax benefits would not impact earnings but does have a cash flow impact of $33.2 million in fourth quarter 2005 and $33.1 million in 2006. There is some uncertainty in the new guidance. PSE believes that the new Regulations require the Company to repay the accumulated tax benefits over the 2005 and 2006 tax years and that the tax deductions claimed on the Company's tax returns were appropriate based on the applicable statutes, Regulations and case law in effect at the time. However, there is no assurance that PSE's position will prevail. If the Company is unsuccessful, a charge for interest expense could apply.

On October 19, 2005, PSE filed an accounting petition with the Commission to defer the capital costs associated with repayment of the deferred tax. The Commission had reduced PSE's rate base by $72 million in its order of February 18, 2005. The accounting petition was approved by the Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005 using PSE's allowed net of tax rate of return. PSE requested recovery of this deferral commencing January 2007 in its February 2006 general rate case filing.

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. The replacement contracts and settlement amounts were ruled prudent in the 2005 PCORC order.

Residential and Small Farm Exchange Benefit Credit. In June 2001, PSE and the 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 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. Pursuant to the amended settlement agreement regarding the Residential Purchase and Sale Program, PSE reduces revenue received from residential and small farm customers 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 that 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 its February 2003 rate case, which established a formula under the BPA rate adjustment clause to be used in adjusting the rate that affects the level of residential exchange benefits for PSE's customers. Adjustments under the formula for the 12-month periods October 1, 2003 through September 30, 2004, and October 1, 2005 through September 30, 2006, are resulting in both a reduction of monthly benefits of $1.0 million and $0.2 million, respectively, for such periods, 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 periods, 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 by BPA under the amended settlement agreement for the period October 1, 2006 through September 30, 2011. The agreement provides that all benefits provided by BPA for 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 BPA's payment of approximately one-half of an available reduction-in-risk discount and deferred BPA's payment of the other half of the discount, plus interest, until the period October 1, 2006 through September 30, 2011.

For 2005 and 2004, the Residential and Farm Energy Exchange Benefit credited to customers was $189.0 million and $182.6 million, respectively, with a related offset to power costs. PSE received payments from BPA in the amount of $175.5 million and $175.9 million during 2005 and 2004, 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 provides for payments from BPA in the amount of $630.6 million for the period January 2003 through September 2006, which amounts are to be passed through to residential and small farm customers of PSE.

For the period October 1, 2006 through September 30, 2011, payments from BPA under the modified amended settlement agreement that are based on formulas, have not yet been determined, but for each 12-month period, October through September, are to be no less than $235.4 million and no more than $530.3 million.

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 or implementing, 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. The parties to these various actions presented oral arguments to the U.S. Ninth Circuit Court of Appeals in November 2005. A decision from the Court is anticipated in 2006. It is not clear what impact, if any, review of such rates and contracts and the above described U.S. Ninth Circuit Court of Appeals actions may have on PSE.

GAS REGULATION AND RATES

General Tariff. 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 was intended to 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%.

On February 15, 2006 PSE filed a request with the Washington Commission to increase gas general rates by 5.3% or $51.3 million, annually, and to approve a depreciation tracker mechanism and a decoupling mechanism for natural gas residential and small commercial customers. The natural gas depreciation tracker is 1.2% or $10.9 million, of rate increase over current rate levels. The gas decoupling mechanism does not have an impact on the current rate increase; however, it is designed to stabilize revenue changes due to load variations between regulatory filings. The resolution of the general rate case may be up to an 11-month process from the time the general rate case is filed.

Purchased Gas Adjustment. PSE has a Purchased Gas Adjustment (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 variations in the gas rates. The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2005, 2004 and 2003:

Effective Date	Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenues (Dollars In Millions)
October 1, 2005	14.7%	$121.6
October 1, 2004	17.6%	121.7
October 1, 2003	13.3%	78.8
April 10, 2003	20.1%	103.6

Accounting Order. On January 25, 2006, the Washington Commission approved an accounting order to defer, as a regulatory liability, two payments in the amount of $42 million and $13 million received from Duke Energy Trading and Marketing in December 2005 in return for assuming the gas transportation capacity on Northwest Pipeline and Westcoast Pipeline from Duke Energy Trading and Marketing. The regulatory liability will be amortized to gas costs from January 2006 through October 2017 based upon the approved schedule. These credits are an offset to gas transportation costs that are in excess of PSE's gas transportation capacity needs. The $42 million payment was received to compensate the Company for the Northwest capacity payments that must be made until February 2011 when the capacity will be needed to serve load. The $13 million payment was received to compensate the Company for the difference between the assumed tariff rates and market value of the Westcoast capacity through October 2017. The Company requested an accounting order to defer the payment as a regulatory liability, matching the related capacity payments for rate purposes.

UTILITY INDUSTRY OVERVIEW

FEDERAL REGULATION

Since the mid-1990s, FERC has required public utilities operating under the Federal Power Act (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 Independent System Operator (ISO); or, alternatively, to describe its efforts to participate in an RTO/ISO or the obstacles to such participation. PSE has been an active participant in regional efforts to form an RTO/ISO in the Pacific Northwest, known as Grid West, since issuance of Order No. 2000. However, in November 2005, PSE withdrew from Grid West at the same time as the region's dominant transmission provider, BPA. PSE has continued to work with BPA and other regional transmission owners to form a new organization, known as ColumbiaGrid, to address the transmission related issues in the region. Any decision by PSE to participate in ColumbiaGrid 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/ISO or whether any future decisions to join (or not to join) an RTO/ISO 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. On July 19, 2005, FERC issued an order terminating the SMD NOPR proceeding given the significant progress made by the industry in developing voluntary RTOs/ISOs. In its July 19, 2005 order, FERC indicated that it would instead consider revisions to its standard Open Access Transmission Tariff (OATT). PSE cannot predict whether any future revisions to its OATT 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 2005, 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 and large-volume, interruptible gas sales.

ELECTRIC UTILITY OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	2005	2004	2003
Generation and purchased power, MWh			
Company-controlled resources	6,902,040	7,048,270	6,965,840
Contracted resources	9,606,880	9,421,546	11,021,471
Non-firm energy purchased[1]	7,299,139	6,164,457	5,179,302
Total generation and purchased power	23,808,059	22,634,273	23,166,613
Less: losses and company use	(1,448,214)	(1,432,686)	(1,338,401)
Total energy sales, MWh	22,359,845	21,201,587	21,828,212
Electric energy sales, MWh			
Residential	10,321,984	10,028,150	9,845,854
Commercial	8,647,478	8,449,566	8,222,166
Industrial	1,357,973	1,352,660	1,372,815
Other customers	105,388	94,034	93,438
Total energy billed to customers	20,432,823	19,924,410	19,534,273
Unbilled energy sales – net increase (decrease)	40,015	(40,217)	65,082
Total energy sales to customers	20,472,838	19,884,193	19,599,355
Sales to other utilities and marketers[1]	1,887,007	1,317,394	2,228,857
Total energy sales, MWh	22,359,845	21,201,587	21,828,212
Less: optimization purchases for sales to other utilities and marketers	--	--	(62,200)
Transportation, including unbilled	2,030,457	1,988,965	2,020,562
Net electric energy sales and transportation, MWh	24,390,302	23,190,552	23,786,574

1 *In 2003, non-firm energy purchased and sales to other utilities and marketers was 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 was reduced 2,941,707 MWh.*

TWELVE MONTHS ENDED DECEMBER 31	2005	2004	2003
Electric operating revenues by classes (thousands):			
Residential	$ 690,184	$ 628,869	$ 603,722
Commercial	629,008	580,973	556,038
Industrial	93,922	88,779	88,201
Other customers	76,153	58,007	54,259
Operating revenues billed to customers[1]	1,489,267	1,356,628	1,302,220
Unbilled revenues – net increase (decrease)	9,548	(813)	4,193
Total operating revenues from customers	1,498,815	1,355,815	1,306,413
Transportation, including unbilled	9,027	10,707	11,542
Sales to other utilities and marketers[2]	105,027	56,512	84,994
Less: optimization purchases for sales to other utilities and marketers	--	--	(2,206)
Total electric operating revenues	$ 1,612,869	$ 1,423,034	$ 1,400,743
Number of customers served (average):			
Residential	893,576	877,711	854,088
Commercial	111,587	109,238	108,479
Industrial	3,877	3,980	3,952
Other	2,426	2,197	2,060
Transportation	17	17	16
Total customers (average)	1,011,483	993,143	968,595
Average kWh used per customer:			
Residential	11,551	11,425	11,528
Commercial	77,495	77,350	75,795
Industrial	350,264	339,864	347,372
Other	43,441	42,801	45,358
Average revenue billed per customer:			
Residential	$ 772	$ 716	$ 707
Commercial	5,637	5,318	5,126
Industrial	24,225	22,306	22,318
Other	31,390	26,403	26,339
Average retail revenues per kWh sold:			
Residential	$ 0.0669	$ 0.0627	$ 0.0617
Commercial	0.0727	0.0688	0.0680
Industrial	0.0692	0.0656	0.0650
Average retail revenue per kWh sold	0.0695	0.0655	0.0646
Heating degree days	4,489	4,421	4,527
Percent of normal – NOAA 30-year average	93.6%	91.8%	94.4%
Load factor[3]	57.4%	53.5%	58.9%

[1] *Operating revenues in 2004 and 2003 were reduced by $0.8 million and $7.7 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 bond was paid and any excess collections were recorded as a reduction in revenues.*

[2] *Sales to other utilities and marketers in 2003 was 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 and MWhs from other utilities and marketers were reduced by $108.7 million and 2,941,707 MWh in 2003.*

[3] *Average usage by customers divided by their maximum usage.*

ELECTRIC SUPPLY

At December 31, 2005, PSE's electric power resources were approximately 4,283 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 may supplement 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 2005, PSE's total electric energy production was supplied 28.9% by its own resources, 22.7% through long-term contracts with several of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River and 17.7% from other firm purchases. Short-term wholesale purchases, net of sales to other utilities and marketers, accounted for 24.7% of energy production in 2005. When it is more economic to purchase power than to run the Company's generation, PSE will purchase in the short-term markets.

The following table shows PSE's electric energy supply resources at December 31, 2005 and 2004 and energy production during the year:

	Peak Power Resources At December 31,				Energy Production			
	2005		2004		2005		2004	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts	1,212	28.3%	1,350	31.0%	5,397,825	22.7%	5,231,691	23.1%
Other hydroelectric[1]	164	3.8%	177	4.1%	590,263	2.5%	600,557	2.7%
Other producers[1]	944	22.1%	1,011	23.2%	3,618,792	15.2%	3,589,298	15.9%
Short-term wholesale energy purchases[2]	N/A	N/A	N/A	N/A	7,299,139	30.7%	6,164,457	27.2%
Total purchased	2,320	54.2%	2,538	58.3%	16,906,019	71.1%	15,586,003	68.9%
Company-controlled resources:								
Hydroelectric	234	5.5%	234	5.4%	879,493	3.7%	1,130,180	5.0%
Coal	677	15.8%	677	15.6%	5,175,799	21.7%	5,119,002	22.6%
Natural gas/oil	902	21.0%	902	20.7%	813,078	3.4%	799,088	3.5%
Wind[3]	150	3.5%	--	--	33,670	0.1%	--	--
Total Company-controlled	1,963	45.8%	1,813	41.7%	6,902,040	28.9%	7,048,270	31.1%
Total	4,283	100.0%	4,351	100.0%	23,808,059	100.0%	22,634,273	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 1,887,007 MWh and 1,317,394 MWh account for 24.7% and 22.7% of energy production for 2005 and 2004, respectively.*

3 *Represents the Company's Hopkins Ridge wind project, which began commercial operations on November 27, 2005.*

LEAST COST PLAN

PSE filed its electric Least Cost Plan on May 2, 2005 with the Washington Commission. The plan supports a strategy of diverse electric power and demand resource acquisitions including resources fueled by natural gas and coal, renewable resources (e.g. wind and biomass), and the implementation of energy efficiency strategies. The Least Cost Plan was followed by an all-source request for proposal (RFP) issued on November 1, 2005. The Washington Commission approved the all-source RFP on October 28, 2005.

Based on 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 average MW shortfall for the period 2006 through 2010 is as follows:

	2006	2007	2008	2009	2010
Projected Average MW Shortfall[1]	233	283	305	362	457

1 *Estimated using all resources under long-term contracts and Company-controlled resources. Also includes completion of the Hopkins Ridge wind project and projected completion of the Wild Horse wind project.*

PSE expects to address this shortfall position with the use of a combination of new long-term power contracts and the purchase or construction of new generating resources as outlined in the Least Cost Plan and all-source RFP.

COMPANY – CONTROLLED ELECTRIC GENERATION RESOURCES

At December 31, 2005, PSE has the following plants with an aggregate net generating capacity of 1,963 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
Hopkins Ridge	Wind	150	2005

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 for a 30 to 50 year period. 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. FERC regulates dam safety and administers proceedings under the FPA to license jurisdictional hydropower projects.

PSE owns three operating hydroelectric projects: the Baker River project, the Snoqualmie Falls project and the Electron project. PSE’s 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.

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 non-governmental 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 for a new license of 45 years or more. The proposed settlement would require an investment of approximately $360 million over the next 30 years (capital expenditures and operations and maintenance cost) in order to implement the conditions of the new license. 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. On May 15, 2005, PSE received notice that FERC would issue a Draft Environmental Impact Statement (DEIS) in lieu of an Environmental Assessment (EA) for the Baker River project. FERC anticipates issuing the DEIS in the first quarter 2006. The contents of the DEIS and potential impacts on the proposed settlement for the new license are as yet unknown. Further actions at FERC could have an impact on the schedule for issuing a new license.

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 after 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. On March 1, 2005, FERC issued an Order on Rehearing and Dismissing Stay Request. The order requires additional flows at Snoqualmie Falls during certain times of the year. PSE requested rehearing of the order on the grounds that the order interferes with the Washington State Department of Ecology's authority to regulate water quality and that FERC arbitrarily and capriciously rebalance the public interest without support of substantive evidence in the record. The Snoqualmie Tribe appealed FERC's operating license decision to the United States Court of Appeals for the Ninth Circuit and PSE intervened in that proceeding. PSE's request for rehearing was denied on June 1, 2005 and on July 8, PSE asked for further review by the Ninth Circuit. The two petitions have been consolidated and briefing is anticipated to be completed in the second quarter 2006.

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, 2005, the White River project net book value totaled $66.1 million, which included $45.0 million of net utility plant, $15.7 million of capitalized FERC licensing costs, $3.7 million of costs related to construction work in progress and $1.3 million related to dam operations and safety. PSE sought recovery of the relicensing, other construction work in progress and dam operations and safety costs in its general rate filing of April 2004 over a 10-year amortization period. On February 18, 2005, the Washington Commission agreed to allow PSE to recover the White River net utility plant costs noted above. However, amortization of the FERC licensing and other costs will not begin until all costs and any sales proceeds are known.

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 sought 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, and Ecology has not recommended any such further actions.

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 2005, 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 2010, unless terminated prior to that date.

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 during the first quarter of 2006; 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 2005, approximately 22.7% of PSE's energy output was obtained at an average cost of approximately $0.0140 per kWh through long-term contracts with several of the Washington PUDs that own and operate hydroelectric projects on the Columbia River. PSE purchases a "pro rata share" of power from the Columbia River projects which requires PSE to pay a proportionate share of the annual debt service, operating and maintenance costs, and other expenses associated with each project in proportion to the contractual shares that PSE obtains from that project. In these instances, PSE's 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.

PSE has contracted to purchase from Douglas County PUD 29.9% (251 MW of peak capacity as of December 31, 2005) of the annual output of the Wells project. This percentage results from a reduction in PSE's prior share by approximately 1.4%, effective April 1, 2005, as a result of a settlement between Douglas County PUD and the Colville Confederated Tribes (Colville Tribe) concerning claims asserted by the Colville Tribe against Douglas County PUD for the use by the Wells project of Tribal lands. PSE's percentage of 29.9% will remain unchanged for the remainder of the contract, which expires in 2018.

PSE has contracted to purchase from Chelan County PUD (Chelan) 38.9% (501 MW of peak capacity as of December 31, 2005) 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 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, 2005, PSE's aggregate capacity from all units of the Rock Island project was 352 MW. PSE's share of the output of the additional Rock Island units was reduced to 55% on July 1, 2005 and Chelan will make its final withdrawal on November 1, 2006 for use in meeting its local load, reducing PSE's share to 50%. PSE's share of the additional Rock Island units will then remain unchanged for the remainder of the contract.

On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25% of the output of Chelan's Rocky Reach and Rock Island hydroelectric generating facilities located on the mid-Columbia River in exchange for PSE paying 25% of the operating costs of the facilities. PSE's share of the output represents approximately 487 MW of capacity and 243 average MW of energy. The agreements terminate in 2031 and provide that PSE will begin to receive power upon expiration of PSE's existing long-term contracts with Chelan for the Rocky Reach and Rock Island output (expiring in 2011 and 2012, respectively). The agreements are subject to approval by FERC and require PSE to make a non-refundable capacity reservation payment of $89 million within 30 days of receipt of such approval. PSE believes that the new agreements with Chelan will lower its overall power costs during the 20-year contract period compared to other available alternatives, secure critical operational flexibility, reduce PSE's projected long-term energy and capacity deficit and continue PSE's long-term relationship with the public utility district. PSE will seek an accounting order from the

Washington Commission for rate base treatment of this payment, and approval to recognize such payment as a regulatory asset.

PSE has contracted to purchase from Grant County PUD 10.8% (103 MW of peak capacity as of December 31, 2005) of the annual output of the Wanapum Development, which percentage remains unchanged for the remainder of the original contract term expiring in 2009. In 2002, PSE signed two new contracts for the Priest Rapids and Wanapum Developments. 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. The new contracts' terms began in November 2005 for the Priest Rapids Development and will begin in November 2009 for the Wanapum Development. Unlike the original contracts for the Wanapum Development and the recently expired contract for the Priest Rapids Development, the new contracts require PSE's share of power from the developments to decline as Grant County PUD's load increases. On November 1, 2005, PSE's share of the output of the Priest Rapids Development, under the new contract, was reduced from 8% to 7.4% (67 MW of peak capacity). For calendar year 2006, PSE's share declines to 4.3% (39 MW of peak capacity).

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. Both the Yakama Nation and Grant County PUD appealed the FERC decision to the Ninth Circuit Court of Appeals. The appeal is still pending, but is in a mediation process.

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 44.6 average MW of energy and 82 MW of capacity for contract year 2005-2006, 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 60.5 MW of exchange energy to BPA in all months except May, July and August for contract year 2005-2006. The contract terminates June 30, 2017, but may be terminated 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. The contract deliveries are contingent on the combined availability of Colstrip Units 3 & 4. The contract payments consist of a monthly fixed payment, due whether energy is received that month or not, and an energy payment, which is based on NorthWestern's commodity and transportation costs for coal. The fixed payment may be reduced if the delivered energy is less than the adjusted energy entitlement (equal to an Equivalent Availability of approximately 73%) for the Contract Year.

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 January 6, 1993, from another natural gas-fired cogeneration facility owned and operated by March Point, which 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 April 8, 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, 2005 was $184.1 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, 2005 was $7.1 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 13 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 2,600 MW.

PSE's transmission expenses were $47.6 million in 2005, $5.7 million higher than 2004. BPA's transmission rates increased an average of 12.5% effective October 1, 2005. BPA's rate increase had a direct impact to PSE's transmission costs, as BPA is PSE's primary transmission provider. These costs are recovered through the PCA mechanism.

In June 2005, BPA and PSE signed a 150 MW Point-to-Point Transmission Agreement for Hopkins Ridge. Transmission service began January 1, 2006 and will continue until February 29, 2024.

GAS UTILITY OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	2005	2004	2003
Gas operating revenues by classes (thousands):			
Residential	$ 592,361	$ 478,969	$ 401,717
Commercial firm	234,342	187,262	149,671
Industrial firm	38,380	30,472	24,164
Interruptible	56,928	46,900	34,046
Total retail gas sales	922,011	743,603	609,598
Transportation services	13,277	12,968	13,796
Other	17,227	12,735	10,836
Total gas operating revenues	$ 952,515	$ 769,306	$ 634,230
Number of customers served (average):			
Residential	629,563	610,181	583,439
Commercial firm	50,148	49,050	46,813
Industrial firm	2,651	2,688	2,685
Interruptible	528	574	611
Transportation	129	129	134
Total customers	683,019	662,622	633,682
Gas volumes, therms (thousands):			
Residential	510,026	489,036	500,116
Commercial firm	225,389	217,346	216,951
Industrial firm	38,576	36,751	36,890
Interruptible	61,769	65,425	61,739
Total retail gas volumes, therms	835,760	808,558	815,696
Transportation volumes	198,504	201,642	209,497
Total volumes	1,034,264	1,010,200	1,025,193
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	70,303	70,986	60,365
AECO hub - Canada	14,820	--	--
Clay Basin	38,857	55,044	49,314
Average therms used per customer:			
Residential	810	801	857
Commercial firm	4,494	4,431	4,634
Industrial firm	14,551	13,672	13,739
Interruptible	116,987	113,981	101,046
Transportation	1,538,791	1,563,116	1,563,410
Average revenue per customer:			
Residential	$ 941	$ 785	$ 689
Commercial firm	4,673	3,818	3,197
Industrial firm	14,478	11,336	9,000
Interruptible	107,818	81,707	55,722
Transportation	102,922	100,527	102,955
Average revenue per therm sold:			
Residential	$ 1.161	$ 0.979	$ 0.803
Commercial firm	1.040	0.862	0.690
Industrial firm	0.995	0.829	0.655
Interruptible	0.922	0.717	0.551
Average retail revenue per therm sold	1.103	0.920	0.747
Transportation	0.067	0.064	0.066
Heating degree days	4,489	4,421	4,527
Percent of normal – NOAA 30-year average	93.6 %	91.8 %	94.4 %

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.

	2005		2004	
PEAK FIRM GAS SUPPLY AT DECEMBER 31	Dth per Day	%	Dth per Day	%
Purchased gas supply:				
British Columbia	205,400	22.1%	198,000	22.7%
Alberta	60,000	6.5%	50,000	5.7%
United States	167,800	18.1%	145,000	16.6%
Total purchased gas supply	433,200	46.7%	393,000	45.0%
Purchased storage capacity:				
Clay Basin	45,200	4.9%	48,000	5.5%
Jackson Prairie	55,100	5.9%	55,100	6.3%
AECO hub - Canada	16,700	1.8%	--	--
Liquefied natural gas	70,500	7.6%	70,500	8.1%
Total purchased storage capacity	187,500	20.2%	173,600	19.9%
Owned storage capacity:				
Jackson Prairie	294,700	31.8%	294,700	33.7%
Propane-air and other	12,500	1.3%	12,500	1.4%
Total owned storage capacity	307,200	33.1%	307,200	35.1%
Total peak firm gas supply	927,900	100.0%	873,800	100.0%
Other and commitments with third parties	(41,400)		(53,100)	
Total net peak firm gas supply	886,500		820,700	

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 2005-2006 winter heating season, PSE contracted for approximately 22.1% 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 6.5% of the peak-day requirements. Long-term and winter peaking arrangements with U.S. suppliers make up approximately 18.1% 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, AECO hub (AECO), LNG held at NWP's Plymouth facility and propane-air and other resources, which represent approximately 37.7%, 4.9%, 1.8%, 7.6% and 1.3%, 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. The December 2005 firm gas supply portfolio consists of arrangements with 24 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 1 year to 10 years.

During 2005, approximately 37.9% of gas supplies purchased by PSE originated in British Columbia while 19.8% originated in Alberta and 42.3% originated in the United States. 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 and at AECO in Alberta, Canada adjacent to Duke Energy Gas Transmission (Westcoast). These facilities represent 44.4% 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 of approximately 8,400,000 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 2005, PSE retained maximum firm withdrawal capacity of over 45,000 Dth per day from the Clay Basin facility with total storage capacity of almost 5,419,000 Dth. The Clay Basin capacity is held under two long-term contracts with remaining terms of 7 years and 14 years. The capacity release contracts PSE has with multiple parties at the Clay Basin storage facility have remaining terms of three months to 15 months as of December 31, 2005, with the option for renewal for 12-month terms. One Clay Basin capacity release contract involves an exchange for storage of 2,000,000 Dth at AECO including withdrawal capacity of 16,700 Dth per day, which terminates March 31, 2007. 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, and slow cycle times, 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 is 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 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 13 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 11 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 18 years.

PSE's firm transportation capacity on Westcoast's pipeline, totaling approximately 40,000 Dth per day, has a remaining term of 9 years for approximately 25,000 Dth per day and a remaining term of 13 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 9 years. PSE's has firm capacity on TransCanada's Alberta and British Columbia transportation systems, totaling approximately 80,000 Dth per day. PSE has annual rollover rights for this capacity. 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.

In accordance with its Least Cost Plan, PSE's Core Gas portfolio has acquired additional long-term transportation capacity from British Columbia to PSE's distribution system. Long-term firm transportation capacity on Westcoast and NWP was acquired from Duke Energy Trading and Marketing (DETM) via the capacity release process in December 2005. In return for PSE assuming DETM's capacity contract obligations, PSE received a total of $55 million. Of this one-time payment, $42 million offsets the cost of excess capacity that was acquired on NWP in advance of anticipated need. The remaining $13 million reflects discounted capacity costs as well as mitigation of higher tolls for the Westcoast capacity. PSE filed an accounting petition with the Washington Commission seeking approval to defer the $55 million cash payment as a regulatory liability to customers under PSE's PGA mechanism. On January 25, 2006, the Washington Commission approved PSE's accounting and established the amortization schedule of the regulatory liability in future periods as a reduction in Purchased Gas Costs under the PGA. PSE took title to the capacity, which totals approximately 55,000 Dth per day, beginning January 1, 2006. Beginning in 2012, the allocated capacity on the Westcoast pipeline declines over the remaining term of the contracts. The transportation agreements have termination dates ranging from 2017 to 2018, but PSE retains the right to extend the existing capacity with the pipelines.

CAPACITY RELEASE

FERC provided a capacity release mechanism as the means for holders of firm pipeline and storage entitlements to temporarily or permanently 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 pipeline capacity not utilized during off-peak periods through capacity release. PSE also utilizes capacity release mechanisms to acquire additional assets to serve its growing service territory. WNG CAP I, a PSE subsidiary, provides additional flexibility and benefits from capacity release transactions. Capacity release benefits are passed on to customers through the PGA mechanism.

ENERGY EFFICIENCY

PSE offers programs designed to help new and existing residential, commercial and industrial 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. Energy efficiency programs reduce customer consumption of energy thus impacting energy margins. The impact of load reductions is adjusted in rates at each general rate case.

PSE's two-year savings goals are set based on the Least Cost Plan and in conjunction with the Conservation Resource Advisory Group per the terms of the 2002 Conservation Stipulation Agreement. For 2004-2005, the minimum savings goals to avoid a "penalty" mechanism were set at 23.2 average MW and 3.5 million therms while the "stretch" goals were set at 39.2 average MW and 5 million therms. PSE actually achieved 39.35 average MW and 6.1 million therms of cost-effective energy savings during the two-year timeframe.

For 2006-2007, the minimum savings goals to avoid a "penalty" mechanism are set at 33 average MW and 3.4 million therms with the "stretch" goals set at 40 average MW and 4.2 million therms. If conservation savings are less than 75% of the minimum goal, PSE will be subject to a penalty of $0.8 million. If savings are between 75% and 89% of the minimum goal, PSE will be subject to a penalty of $0.5 million. Savings of between 90% and 99% of the minimum goal will result in a penalty of $0.2 million.

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 margins. The impact of load reductions is adjusted in rates in 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.

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 at the federal or state level, but PSE continues to monitor developments concerning emissions.

The Environmental Protection Agency (EPA) has proposed mercury reductions nationwide and various states have indicated that they may want to pursue more stringent reductions, including the Montana Department of Environmental Quality which is developing a proposed rule that may be issued in draft form by March 2006. Additionally, the state of Washington has introduced mercury reduction legislation in the current legislative session. PSE cannot predict the outcome of these matters or the related potential financial impact.

In December 2003, Colstrip Units 1 & 2 and 3 & 4 received an information request from the 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.

In January 2006, EPA issued a draft settlement agreement related to an Administrative Compliance Order (ACO) pursuant to the Clean Air Act received by Colstrip in December 2003 related to Colstrip Units 3 & 4. The ACO alleged violation of the Clean Air Act permit at Colstrip since 1980 and contended that Colstrip was obligated to submit for review and approval by EPA an analysis and proposal for reducing emissions of nitrogen oxide to address visibility concerns if and when the EPA promulgates Best Available Retrofit Technology requirements for nitrogen oxide emissions. Although Colstrip believes that the ACO is unfounded, Colstrip is discussing the proposed settlement agreement with EPA, the Montana DEQ and the Northern Cheyenne Tribe. The draft settlement agreement would resolve potential liability related to this issue.

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. Since 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, 2005 are listed below. 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	57	Chairman, President and Chief Executive Officer since May 2005; President and Chief Executive Officer, 2002 – 2005. Director since January 2002.
J. W. Eldredge	55	Vice President, Corporate Secretary and Chief Accounting Officer since May 2005; Corporate Secretary and Chief Accounting Officer 1999 – 2005.
D. E. Gaines	48	Vice President Finance and Treasurer since March 2002.
J. L. O'Connor	49	Senior Vice President General Counsel, Chief Ethics and Compliance Officer since October 2005; Vice President and General Counsel, 2003 - 2005.
B. A. Valdman	42	Senior Vice President Finance and Chief Financial Officer since January 2004.

The executive officers of Puget Sound Energy as of December 31, 2005 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	57	Chairman, President and Chief Executive Officer since May 2005; Director since January 2002; President and Chief Executive Officer 2002 – 2005; President and Chief Executive Officer of Reynolds Energy International, 1998 – 2002.
D. P. Brady	41	Senior Vice President Customer Service, Information Technology and Chief Information Officer since October 2005; Vice President Customer Services 2003 – 2005; 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.
P. K. Bussey	49	Senior Vice President Corporate Affairs since October 2005; Vice President Regional and Public Affairs, 2003 – 2005. Prior to joining PSE, he was President of the Washington Round Table, 1996 – 2003.
J. W. Eldredge	55	Vice President, Corporate Secretary, Controller and Chief Accounting Officer since May 2001; Corporate Secretary, Controller and Chief Accounting Officer, 1993 – 2001.
D. E. Gaines	48	Vice President Finance and Treasurer since March 2002; Vice President and Treasurer, 2001 – 2002; Treasurer, 1994 – 2001.
K. J. Harris	41	Senior Vice President Regulatory Policy and Energy Efficiency since October 2005; Vice President Regulatory and Government Affairs, 2003 – 2005; Vice President Regulatory Affairs, 2002 – 2003; Director Load Resource Strategies and Associate General Counsel, 2001 – 2002.
E. M. Markell	54	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	49	Senior Vice President Operations since February 2003; Vice President Operations – Delivery, 1999 – 2003.
M. D. Mellies	45	Vice President Human Resources since October 2005. Prior to joining PSE, she was General Manager of Human Resources at Microsoft, 2002 – 2005. Prior to Microsoft, she was VP Human Resources for Lante Corporation, 1998 – 2001.
J. L. O'Connor	49	Senior Vice President General Counsel, Chief Ethics and Compliance Officer since October 2005; Vice President and General Counsel, 2003 – 2005. Prior to joining PSE, she was interim General Counsel, Starbucks Corporation, 2002; Senior Vice President and Deputy General Counsel, Starbucks Corporation, 2001 – 2002.
J. M. Ryan	43	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.

C. E. Shirley	52	Vice President Energy Efficiency Services since October 2005; Director Energy Efficiency Services, 2002 – 2005. Prior to joining, PSE he was Senior Manager of Energy Services for Snohomish County Public Utility District, 1995 – 2002.
B. A. Valdman	42	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.
P. M. Wiegand	53	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 1A. RISK FACTORS

The following risk factors, in addition to other factors and matters discussed elsewhere in this report, should be carefully considered. The risks and uncertainties described below are not the only risks and uncertainties that Puget Energy and PSE may face. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair PSE's business operations. If any of the following risks actually occur, Puget Energy's and PSE's business, results of operations and financial conditions would suffer.

RISKS RELATING TO THE UTILITY BUSINESS

THE ACTIONS OF REGULATORS CAN SIGNIFICANTLY AFFECT PSE'S EARNINGS, LIQUIDITY AND BUSINESS ACTIVITIES AND ARE LARGELY OUTSIDE PSE'S CONTROL.

The rates that PSE is allowed to charge for its services is the single most important item influencing its financial position, results of operations and liquidity. PSE is highly regulated and the regulation of the rates that it charges its customers is determined by the Washington Commission.

PSE is also subject to the regulatory authority of the Washington Commission with respect to accounting, the issuance of securities and certain other matters, and to the regulatory authority of FERC with respect to the transmission of electric energy, the resale of electric energy at wholesale, accounting and certain other matters. Policies and regulatory actions by these regulators could have a material impact on PSE's financial position, results of operations and liquidity, including actions that relate 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 generation facilities;
- The licensing process with respect to PSE's hydroelectric generation facilities and gas storage facilities;
- Operation of distribution and transmission facilities;
- Recovery of capital investments, including investments in new generation facilities, power and gas costs and regulatory assets; and
- Present and prospective wholesale and retail competition.

PSE'S RECOVERY OF COSTS IS SUBJECT TO REGULATORY REVIEW AND ITS OPERATING INCOME MAY BE ADVERSELY AFFECTED IF ITS COSTS ARE DISALLOWED OR RECOVERY IS DELAYED.

The Washington Commission determines the rates PSE may charge to its retail customers based on a normalized cost of producing power. If in a specific year PSE's costs are higher than normal, rates will not be sufficient to permit PSE to earn the allowed return, or to cover its costs and recovery of energy costs will be deferred until subsequent ratemaking proceedings. For example, the recent increase in wholesale energy prices could result in an underrecovery of PSE's costs. In addition, the Washington Commission decides what level of expense and investment is necessary, reasonable and prudent in providing service. If the Washington Commission decides that part of PSE's costs do not meet the standard, those costs may be disallowed partially or entirely and not recovered in rates. For these reasons, the rates authorized by the Washington Commission may not be sufficient to earn the allowed return or recover the costs incurred by PSE in a given period.

THE MECHANISM BY WHICH VARIATIONS IN PSE'S POWER COSTS ARE APPORTIONED BETWEEN IT AND ITS CUSTOMERS WILL CHANGE IN 2006, AT WHICH TIME PSE COULD EXPERIENCE A SIGNIFICANT INCREASE IN EXPENSES.

PSE has a PCA mechanism that is triggered if its costs to provide customers' electricity fall outside certain bands from a normalized level of power costs. PSE's 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 costs. After June 30, 2006, PSE's share of power cost variations will be apportioned on an annual basis whereby increases or decreases in power costs will be apportioned between PSE and its customers on a graduated scale. (See "PCA Mechanism" under Regulation and Rates section for further details.) Although PSE is required by the Washington Commission to make a power cost only rate case by May 15, 2006 to reset the power cost baseline rates effective July 1, 2006, it is possible that PSE could experience higher expenses associated with excess power under the apportionment arrangement once the cumulative $40 million cap expires. In addition, PSE was required by the

Washington Commission to make a general tariff filing in February 2006 to reset power cost baseline rates effective January 1, 2007.

PSE MAY BE UNABLE TO ACQUIRE ENERGY SUPPLY RESOURCES TO MEET PROJECTED CUSTOMER NEEDS OR MAY FAIL TO SUCCESSFULLY INTEGRATE SUCH ACQUISITIONS.

PSE projects that future energy needs will exceed current purchased and Company-controlled power resources. As part of PSE's business strategy, it plans to acquire additional electric generation and delivery infrastructure to meet customer needs. If PSE cannot acquire further additional energy supply resources at a reasonable cost, it may be required to purchase additional power in the open market at a cost that could significantly increase its expenses and reduce earnings and cash flows. Additionally, PSE may not be able to timely recover all, if any, of those increased expenses through ratemaking.

While PSE expects to identify the benefits of new energy supply resources prior to their acquisition and integration, it may not be able to achieve the expected benefits of such energy supply sources due to, among other things:

- Delays or difficulties in completing the integration of the acquired energy source;
- Higher than anticipated costs or a need to allocate resources to manage unexpected operating difficulties; and
- Reliance on inaccurate assumptions in evaluating the expected benefits.

THE COMPANY'S CASH FLOW AND EARNINGS COULD BE ADVERSELY AFFECTED BY POTENTIAL HIGH PRICES AND VOLATILE MARKETS FOR PURCHASED POWER, INCREASED CUSTOMER DEMAND FOR ENERGY, RECURRENCE OF LOW AVAILABILITY OF HYDROELECTRIC RESOURCES, OUTAGES OF ITS GENERATING FACILITIES OR A FAILURE TO DELIVER ON THE PART OF ITS SUPPLIERS.

The utility business involves many operating risks. If PSE's operating expenses, including the cost of purchased power and natural gas, significantly exceed the levels recovered from retail customers for an extended period of time, its cash flow and earnings would be negatively affected. Factors which could cause purchased power and gas costs to be higher than anticipated include, but are not limited to, high prices in western wholesale markets during periods when PSE has insufficient energy resources to meet its load requirements and/or high volumes of energy purchased in wholesale markets at prices above the amount recovered in retail rates due to:

- Increases in demand due, for example, either to weather or customer growth;
- Below normal energy generated by PSE-owned hydroelectric resources due to low streamflow conditions;
- Extended outages of any of PSE-owned generating facilities or the transmission lines that deliver energy to load centers;
- Failure to perform on the part of any party from which PSE purchases capacity or energy; and
- The effects of large-scale natural disasters, such as the hurricanes recently experienced in the southern United States.

PSE'S ELECTRIC GENERATING FACILITIES ARE SUBJECT TO OPERATIONAL RISKS THAT COULD RESULT IN UNSCHEDULED PLANT OUTAGES, UNANTICIPATED OPERATION AND MAINTENANCE EXPENSES AND INCREASED POWER PURCHASE COSTS.

PSE owns and operates coal, gas-fired, hydro, wind-powered and oil-fired generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- Increased prices for fuel and fuel transportation as existing contracts expire;
- Facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- Disruptions in the delivery of fuel and lack of adequate inventories;
- Labor disputes;
- Inability to comply with regulatory or permit requirements;
- Disruptions in the delivery of electricity;
- Operator error;
- Terrorist attacks; and
- Catastrophic events such as fires, explosions, floods or other similar occurrences affecting the electric generating facilities.

PSE IS SUBJECT TO THE COMMODITY PRICE, DELIVERY AND CREDIT RISKS ASSOCIATED WITH THE ENERGY MARKETS.

In connection with matching loads and resources, PSE engages in wholesale sales and purchases of electric capacity and energy, and, accordingly, is subject to commodity price risk, delivery, credit risk and other risks associated with these activities. Credit risk includes the risk that counterparties owing PSE money or energy will breach their obligations. Should the counterparties to these arrangements fail to perform, PSE may be forced to enter into alternative arrangements. In that event, PSE's financial results could be adversely affected and PSE could incur losses. Although PSE's models take into account the expected probability of default by counterparties, actual exposure to a default by a particular counterparty could be greater than the models predict.

To lower its financial exposure related to commodity price fluctuations, PSE may use forward delivery agreements, swaps and option contracts to hedge commodity price risk with a diverse group of counterparties. However, PSE does not always cover the entire exposure of its assets or positions to market price volatility and the coverage will vary over time. To the extent PSE has unhedged positions or its hedging procedures do not work as planned, fluctuating commodity prices could adversely impact its results of operations.

CONDITIONS THAT MAY BE IMPOSED IN CONNECTION WITH HYDROELECTRIC LICENSE RENEWALS MAY REQUIRE LARGE CAPITAL EXPENDITURES AND REDUCE EARNINGS AND CASH FLOWS.

PSE is in the process of renewing the federal licenses for its Baker River hydroelectric project and implementing the federal licensing requirements for the Snoqualmie Falls hydroelectric project. The relicensing process is a political and public regulatory process that involves sensitive resource issues. PSE cannot predict with certainty the conditions that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued or whether PSE will be willing to meet the relicensing requirements to continue operating these hydroelectric projects.

COSTS OF COMPLIANCE WITH ENVIRONMENTAL AND ENDANGERED SPECIES LAWS ARE SIGNIFICANT AND THE COST OF COMPLIANCE WITH NEW ENVIRONMENTAL OR ENDANGERED SPECIES LAWS AND THE INCURRENCE OF ENVIRONMENTAL LIABILITIES COULD ADVERSELY AFFECT PSE'S RESULTS OF OPERATIONS.

PSE's operations are subject to extensive federal, state and local regulation relating to environmental and endangered species protection. To comply with these legal requirements, PSE must spend significant sums on environmental and endangered species monitoring, pollution control equipment and emission fees. New environmental and endangered species laws and regulations affecting PSE's operations may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to PSE or its facilities, which may substantially increase environmental and endangered species expenditures made by it in the future. In addition, PSE may not be able to recover all of its costs for environmental expenditures through electric and natural gas rates at current levels in the future.

PSE has an ownership interest in coal-fired, steam-electric generating plants at Colstrip, Montana, and owns combustion turbine units, which are fueled by natural gas or oil. These facilities are subject to the federal Clean Air Act Amendments of 1990 and, although the facilities currently meet emission requirements, 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. New federal, state and local regulations regarding air quality and emissions, or revisions or reinterpretations of existing regulations, may be adopted or become applicable to PSE or its facilities. Compliance with these or other future regulations could require significant capital expenditures by PSE and adversely affect PSE's financial position, results of operations, cash flows and liquidity.

With respect to endangered species laws, the listing or proposed listing of several species of salmon in the Pacific Northwest is causing a number of changes to the operations of hydroelectric generating facilities on Pacific Northwest rivers, including the Columbia River. These changes could reduce the amount, and increase the cost, of power generated by hydroelectric plants owned by PSE or in which PSE has an interest, and increase the cost of the permitting process for these facilities.

Under current law, PSE is also generally responsible for any on-site liabilities associated with the environmental condition of the facilities that it currently owns or operates or has previously owned or operated, regardless of whether the liabilities arose before, during or after the time the facility was owned or operated. The incurrence of a material environmental liability or the new regulations governing such liability could result in substantial future costs and have a material adverse effect on PSE's results of operations and financial condition.

THE COMPANY'S BUSINESS IS DEPENDENT ON ITS ABILITY TO SUCCESSFULLY ACCESS CAPITAL MARKETS.

The Company relies on access to both short-term money markets as a source of liquidity and longer-term capital markets to fund its utility construction program and other capital expenditure requirements not satisfied by cash flow from its operations. If the Company is unable to access capital at competitive rates, its ability to pursue improvements or acquisitions, including generating capacity, that may be relied on for future growth, and to otherwise implement its strategy, could be adversely affected.

Certain market disruptions or a downgrade of the Company's credit rating may increase the Company's cost of borrowing or adversely affect the ability to access one or more financial markets. In addition to further economic downturns and the overall health of the utility industry, such disruptions could include:

- The bankruptcy of an unrelated energy company;
- Capital market conditions generally;
- Market prices for electricity and natural gas; or
- Terrorist attacks or threatened attacks.

A DOWNGRADE IN THE COMPANY'S CREDIT RATING COULD NEGATIVELY AFFECT ITS ABILITY TO ACCESS CAPITAL AND THE ABILITY TO HEDGE IN WHOLESALE MARKETS.

Standard and Poor's and Moody's Investor Services rate PSE's senior secured debt at "BBB" with a stable outlook and "Baa2" with a stable outlook, respectively. Although the Company is not aware of any current plans of S&P or Moody's to lower their respective ratings on PSE's debt, the Company cannot be assured that such credit ratings will not be downgraded.

Although neither Puget Energy nor PSE has any rating downgrade triggers that would accelerate the maturity dates of outstanding debt, 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 corporate credit ratings decline. A downgrade in commercial paper ratings could preclude PSE's ability to issue commercial paper under its current programs.

Any downgrade below investment grade of PSE's senior secured debt could allow counterparties 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 COMPANY'S OPERATING RESULTS FLUCTUATE ON A SEASONAL AND QUARTERLY BASIS.

PSE's business is seasonal and weather patterns can have a material impact on its operating performance. Because natural gas is heavily used for residential and commercial heating, demand depends heavily on weather patterns in PSE's service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. However, the recent increase in the price of natural gas may result in decreased customer demand, despite normal or lower than normal temperatures. Demand for electricity is also greater in the winter months associated with heating. Accordingly, PSE's operations have historically generated less revenues and income when weather conditions are milder in the winter. In the event that the Company experiences unusually mild winters, results of operations and financial condition could be adversely affected.

THE COMPANY MAY BE ADVERSELY AFFECTED BY LEGAL PROCEEDINGS ARISING OUT OF THE ELECTRICITY SUPPLY SITUATION IN THE WESTERN POWER MARKETS, WHICH COULD RESULT IN REFUNDS OR OTHER LIABILITIES.

The Company is involved in a number of legal proceedings and complaints with respect to power markets in the western United States. Most of these proceedings relate to the significant increase in the spot market price of energy in western power markets in 2000 and 2001, which allegedly contributed to or caused unjust and unreasonable prices and allegedly may have been the result of manipulations by certain other parties. These proceedings include, but are not limited to, refund proceedings and hearings in California and the Pacific Northwest and complaints and cross-complaints filed by various parties with respect to alleged misconduct by other parties in western power markets. 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.

RISKS RELATING TO DISPOSITION OF DISCONTINUED OPERATIONS

UNTIL INFRASTRUX IS SOLD, PUGET ENERGY MAY BE REQUIRED TO REDUCE THE CARRYING VALUE OF INFRASTRUX OWNERSHIP INTEREST, WHICH COULD HAVE A NEGATIVE EFFECT ON THE COMPANY'S FINANCIAL POSITION.

Puget Energy's plan to dispose of its interest in InfrastruX meets the criteria established for recognition of InfrastruX as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in the Company's consolidated financial statements in 2005. Pursuant to SFAS No. 144, the Company is required to re-assess the carrying value of its investment in InfrastruX at the end of each fiscal quarter and the carrying value could be significantly reduced in future periods due to a deterioration in InfrastruX's financial performance or market conditions in the utility construction services sector generally. InfrastruX's operations may be affected by various factors, including:

- The inability to generate internal growth, which could be affected by, among other factors, InfrastruX's ability to maintain current key customer relationships, 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 impairments on the carrying value of the investment in InfrastruX;
- 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;
- The perception of risk associated with its business due to a challenging business environment;
- Risks related to regulatory compliance issues; and
- Pending or threatened litigation or government investigations, relatively common in the utility construction industry, may create uncertainty and expose InfrastruX to potential liabilities.

PUGET ENERGY MAY BE UNABLE TO COMPLETE THE SALE OF ITS INTEREST IN INFRASTRUX ON REASONABLE TERMS.

Puget Energy is committed to a sale of InfrastruX. Puget Energy has retained an investment banking firm to assist Puget Energy to complete a sale, although a sale is not assured. Puget Energy's carrying value at December 31, 2005 reflects Puget Energy's best estimate of the fair value of its InfrastruX investment. Net proceeds on the ultimate sale could vary from this estimate.

PUGET ENERGY'S LIQUIDITY AND FINANCIAL CONDITION COULD BE ADVERSELY IMPACTED IF INFRASTRUX IS UNABLE TO SATISFY ITS OBLIGATIONS UNDER ITS REVOLVING CREDIT FACILITY.

In May 2004, InfrastruX secured a three-year credit agreement with several banks to provide up to $150 million in financing. Puget Energy is the guarantor of this line of credit.

If InfrastruX is unable to generate cash flow from operations or to access other financing sources in an amount sufficient to service its obligations under the credit agreement, Puget Energy, as the guarantor, may be required to satisfy these obligations. Currently, Puget Energy does not have a liquidity facility in place to support its guarantor obligations, and there can be no assurance that such a facility could be obtained on favorable terms, if at all. In the event Puget Energy is required, as guarantor, to repay amounts owed under the credit agreement, its liquidity and access to capital could be negatively impacted.

RISKS RELATING TO PUGET ENERGY'S CORPORATE STRUCTURE

AS A HOLDING COMPANY, PUGET ENERGY IS SUBJECT TO RESTRICTIONS ON ITS ABILITY TO PAY DIVIDENDS.

As a holding company with no significant operations of its own, the primary source of funds for the payment of dividends to its shareholders is dividends PSE pays to Puget Energy. PSE is a separate and distinct legal entity and has no obligation to pay any amounts to Puget Energy, whether by dividends, loans or other payments. The ability of PSE to pay dividends or make distributions to Puget Energy, and accordingly, Puget Energy's ability to pay dividends on its common stock, will depend on its earnings, capital requirements and general financial condition. If Puget Energy does not receive adequate distributions from PSE, then it may not be able to make or may have to reduce dividend payments on its common stock.

PSE's payment of common stock dividends to Puget Energy is restricted by provisions of covenants applicable to its preferred stock and long-term debt contained in its articles of incorporation and electric and gas mortgage indentures. Puget

Energy's Board of Directors reviews the dividend policy periodically in light of the factors referred to above, and cannot assure you of the amount of dividends, if any, that may be paid in the future.

FUTURE SALES OF PUGET ENERGY'S COMMON STOCK ON THE PUBLIC MARKET COULD LOWER THE STOCK PRICE.

Puget Energy may sell additional shares of common stock in public offerings, through the stock purchase and dividend reinvestment plan or through common stock offering programs which it has entered into with two financial institutions. Puget Energy cannot predict the size of future issuances of common stock, or the effect, if any, that future issuances and sales of shares of common stock will have on the market price of common stock. Sales of substantial amounts of common stock, or the perception that such sales could occur, may adversely affect the prevailing market price of common stock.

THE MARKET PRICE FOR COMMON STOCK IS UNCERTAIN AND MAY FLUCTUATE SIGNIFICANTLY.

Puget Energy cannot predict whether the market price of its common stock will rise or fall. Numerous factors influence the trading price of its common stock. These factors may include changes in financial condition, results of operations and prospects, legal and administrative proceedings and political, economic, financial and other factors that can affect the capital markets generally, the stock exchanges on which Puget Energy's common stock is traded and its business segments.

CERTAIN PROVISIONS OF LAW, AS WELL AS PROVISIONS IN THE RESTATED ARTICLES OF INCORPORATION, BYLAWS AND SHAREHOLDERS RIGHTS PLAN, MAY MAKE IT MORE DIFFICULT FOR OTHERS TO OBTAIN CONTROL OF PUGET ENERGY, EVEN THOUGH SOME SHAREHOLDERS MIGHT CONSIDER THIS FAVORABLE.

Puget Energy is a Washington corporation and certain anti-takeover provisions of Washington laws apply and create various impediments to the acquisition of control of Puget Energy or to the consummation of certain business combinations. In addition, Puget Energy's restated articles of incorporation, bylaws and shareholders rights plan contain provisions which may make it more difficult to remove incumbent directors or effect certain business combinations with Puget Energy without the approval of the Board of Directors. These provisions of law and of Puget Energy's corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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.

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, 2005. 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.

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 21, 2006, there were approximately 38,300 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 2005 and 2004. Puget Energy and its predecessor companies have paid dividends on common stock each year since 1943 when such stock first became publicly held.

	2005			2004		
	Price Range		Dividends	Price Range		Dividends
Quarter Ended	High	Low	Paid	High	Low	Paid
March 31	$24.60	$21.30	$0.25	$23.92	$21.59	$0.25
June 30	23.56	20.73	0.25	22.88	20.51	0.25
September 30	24.36	22.05	0.25	23.00	21.05	0.25
December 31	23.70	20.21	0.25	24.81	22.27	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 $331.9 million at December 31, 2005.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected financial data.

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

YEARS ENDED DECEMBER 31	2005	2004	2003[1]	2002	2001
Operating revenue [2]	$ 2,573,210	$ 2,198,877	$ 2,041,016	$ 1,995,652	$ 2,712,774
Operating income	303,163	287,678	297,723	294,074	288,419
Net income from continuing operations	146,283	125,410	114,600	100,597	110,656
Net income	155,726	55,022	116,197	110,052	98,426
Basic earnings per common share from continuing operations	1.43	1.26	1.21	1.13	1.28
Basic earnings per common share	1.52	0.55	1.23	1.24	1.14
Diluted earnings per common share from continuing operations	1.42	1.26	1.20	1.13	1.28
Diluted earnings per common share	1.51	0.55	1.22	1.24	1.14
Dividends per common share	$ 1.00	$ 1.00	$ 1.00	$ 1.21	$ 1.84
Book value per common share	17.52	16.24	16.71	16.27	15.66
Total assets at year end	$ 6,609,951	$ 5,851,219	$ 5,708,724	$ 5,772,132	$ 5,668,481
Long-term debt	2,183,360	2,069,360	1,955,347	2,021,832	2,053,815
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	43,162	50,662
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	--	300,000	300,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	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 expenses 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] *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 is not available, and therefore revenue and expense were not adjusted for the effects of EITF No. 03-11 in the year.*

PUGET SOUND ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS)

YEARS ENDED DECEMBER 31	2005	2004	2003[1]	2002	2001
Operating revenue [2]	$ 2,573,210	$ 2,198,877	$ 2,041,016	$ 1,995,652	$ 2,712,774
Operating income	303,496	288,241	297,904	294,593	288,480
Net income for common stock	146,769	126,192	114,735	101,117	95,968
Total assets at year end	$ 6,339,800	$ 5,579,756	$ 5,359,104	$ 5,453,390	$ 5,317,750
Long-term debt	2,183,360	2,064,360	1,950,347	2,021,832	2,053,815
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	43,162	50,662
Corporation obligated, mandatorily redeemable preferred securities of subsidiary trust holding solely junior subordinated debentures of the corporation	--	--	--	300,000	300,000
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	280,250	280,250	--	--

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[2] *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 is not available, and therefore revenue and expense were not adjusted for the effects of EITF No. 03-11 in the year.*

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 of 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. Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy intends to monetize its interest in InfrastruX through a sale. See section titled "InfrastruX" for further discussion.

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 Utilities and Transportation Commission (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 wholesale market stability over time.

PSE's main operational objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE intends to be more self-sufficient in energy generation resources. Owning more generation resources will reduce the Company's reliance on the wholesale energy market. PSE is continually exploring for new electric-power resource generation and long-term power purchase agreements to meet this goal. The completion of the Hopkins Ridge wind project in the fourth quarter 2005 and the closing of its acquisition of the Wild Horse wind project in the third quarter 2005 are two steps in reaching this goal. The Hopkins Ridge wind project was placed into service on November 27, 2005 and is designed to provide approximately 150 MW of capacity or 52 average MW. PSE also issued notice to proceed with construction of the Wild Horse wind project in the third quarter 2005 which is expected to be completed by December 31, 2006. The Wild Horse wind project is designed to provide approximately 230 MW of capacity or 73 average MW. The Wild Horse wind project will require approximately $317.4 million in capital requirements in 2006, in addition to $62.6 million spent in 2005. Included in the $317.4 million estimate is the cost to acquire land, wind turbines and other necessary assets, construction costs, and transaction, financing and contingency costs. Together these wind electric generation resources will serve the needs of approximately 123,000 of PSE's electric customers.

The Hopkins Ridge wind project and the Wild Horse wind project were included as part of PSE's energy resource portfolio in its long-term electric Least Cost Plan that was filed May 2, 2005 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. The Least Cost Plan was followed by issuing an all-source request for proposal (RFP) on November 1, 2005. PSE obtained approval of the all-source RFP from the Washington Commission on October 28, 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. Puget Energy intends to monetize its interest in InfrastruX through a sale.

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 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 2005 was $155.7 million on operating revenues from continuing operations of $2.6 billion compared to $55.0 million on operating revenues from continuing operations of $2.2 billion in 2004 and $116.2 million on operating revenues from continuing operations of $2.0 billion in 2003. Income from continuing operations in 2005 was $146.3 million compared to $125.4 million in 2004 and $114.6 million in 2003.

Basic earnings per share in 2005 were $1.52 on 102.6 million weighted average common shares outstanding compared to $0.55 on 99.5 million weighted average common shares outstanding in 2004 and $1.23 on 94.8 million weighted average common shares outstanding in 2003. Diluted earnings per share in 2005 were $1.51 on 103.1 million weighted average common shares outstanding compared to $0.55 on 99.9 million weighted average common shares outstanding in 2004 and $1.22 on 95.3 million weighted average common shares outstanding in 2003. Included in basic and diluted earnings per share for 2005 was $0.09, compared to $(0.71) and $0.02 for 2004 and 2003, respectively related to discontinued operations.

Net income in 2005 was positively impacted by an increase in income from continuing operations of $20.6 million due to increased electric and gas margins of $73.4 million. This increase was due primarily to a higher Tenaska disallowance in 2004 of $43.4 million compared to $4.1 million in 2005. Increased electricity and gas sales volumes increased margin by $24.5 million as compared to 2004. Gas margin also increased $17.3 million as a result of the 2005 gas general rate case, partially offset by a $5.0 million one-time true-up of previously reported gas costs. Offsetting the increases were higher operations and maintenance costs of $42.1 million and depreciation and amortization of $13.0 million. In addition, income from discontinued operations increased $79.9 million in 2005 compared to 2004 primarily due to lower non-cash impairments and favorable industry conditions in the utility construction services sector. In 2005, Puget Energy recorded carrying value adjustments on the InfrastruX investment and related transaction costs of $12.4 million. In 2004, InfrastruX recorded a $91.2 million ($76.6 million after tax and minority interest) goodwill impairment charge. 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 results were 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 which occurred 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.

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 and its lowest sales in the third quarter 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
2005 COMPARED TO 2004

ENERGY MARGINS

PSE uses the following margin information in reviewing its operations to determine whether PSE is collecting the appropriate amount of energy costs from its customers to allow operating cost recovery.

The following table displays the details of electric margin changes from 2004 to 2005. 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.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	ELECTRIC MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 1,436.4	$ 1,310.9	$ 125.5	9.6 %
Electric transportation revenue	9.0	10.7	(1.7)	(15.9)
Other electric revenue-gas supply resale	26.1	11.5	14.6	127.0
Total electric revenue for margin[1]	1,471.5	1,333.1	138.4	10.4
Adjustments for amounts included in revenue:				
Pass-through tariff items	(26.9)	(25.4)	(1.5)	(5.9)
Pass-through revenue-sensitive taxes	(104.9)	(94.2)	(10.7)	(11.4)
Residential exchange credit	180.5	174.5	6.0	3.4
Net electric revenue for margin	1,520.2	1,388.0	132.2	9.5
Minus power costs:				
Electric generation fuel	(73.3)	(80.7)	7.4	9.2
Purchased electricity, net of sales to other utilities and marketers[2]	(776.4)	(660.3)	(116.1)	(17.6)
Total electric power costs[3]	(849.7)	(741.0)	(108.7)	(14.7)
Electric margin before PCA	670.5	647.0	23.5	3.6
Tenaska disallowance reserve	5.3	(26.0)	31.3	*
Power cost deferred under the PCA mechanism	15.7	19.1	(3.4)	(17.8)
Electric margin[4]	$ 691.5	$ 640.1	$ 51.4	8.0 %

** Percent change not applicable.*

[1] *For 2005, total electric revenue for margin was $1,471.5 million, which does not include $105.0 million in sales to other utilities and marketers and $36.4 million in other miscellaneous electric revenue included in electric operating revenues of $1,612.9 million. For 2004, total electric revenue for margin was $1,333.1 million, which does not include $56.5 million in sales to other utilities and marketers and $33.4 million in other miscellaneous electric revenues included in electric operating revenues of $1,423.0 million.*

[2] *For 2005, purchased electricity, net of sales to other utilities and marketers, was $776.4 million excluding sales to other utilities and marketers of $105.0 million and including the Tenaska reserve turnaround of $(5.3) million and power cost deferral under the PCA mechanism of $(15.7) million, purchased electricity was $860.4 million. For 2004, purchased electricity, net of sales to other utilities and marketers, was $660.3 million, excluding sales to other utilities and marketers of $56.5 million and including the Tenaska disallowance reserve of $36.5 million, the Tenaska reserve turnaround of $(10.5) and the power cost deferral under the PCA mechanism of $(19.1) million, purchased electricity was $723.6 million.*

[3] *For 2005, total electric power costs were $849.7 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(180.5) million and unrealized net loss on derivative instruments of $0.5 million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $753.7 million. For 2004, total electric power costs were $741.0 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(174.5) million and unrealized net gain on derivative instruments of $(0.5) million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $629.3 million.*

[4] *Electric margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

Electric margin increased $51.4 million in 2005 compared to 2004 primarily as a result of the Tenaska disallowance recorded in May 2004, and ongoing Tenaska disallowances, which reduced margin by $43.4 million for 2004 compared to $4.1 million in 2005. Other items that increased margin include a 3% increase in retail customer usage which contributed $18.7 million to margin. These increases were partially offset by a reduction in transmission and transportation revenues in 2005 compared to 2004 which reduced electric margin by $2.7 million. Customers also received a reduction in revenue of $2.6 million related to production tax credits for the Hopkins Ridge wind generating facility which lowered electric revenue and margin. These credits will vary quarter to quarter and over time the amounts credited to customers through lower electric rates will equal the amount used for federal income taxes. A lower authorized return on electric generating facilities that became effective on March 4, 2005 also lowered electric margin by $2.3 million.

The following table displays the details of gas margin changes from 2004 to 2005. 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.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2005	 2004	 CHANGE	PERCENT CHANGE
Gas retail revenue	$ 922.0	$ 743.6	$ 178.4	24.0 %
Gas transportation revenue	13.3	13.0	0.3	2.3
Total gas revenue for margin[1]	935.3	756.6	178.7	23.6
Adjustments for amounts included in revenue:				
Pass-through tariff items	(5.7)	(3.6)	(2.1)	(58.3)
Pass-through revenue-sensitive taxes	(73.1)	(59.3)	(13.8)	(23.3)
Net gas revenue for margin	856.5	693.7	162.8	23.5
Minus purchased gas costs[2]	(592.1)	(451.3)	(140.8)	(31.2)
Gas margin[3]	$ 264.4	$ 242.4	$ 22.0	9.1 %

[1] *For 2005, total gas revenue for margin was $935.3 million, which does not include $17.2 million related to other gas operating revenues that is included in gas operating revenues of $952.5 million. For 2004, total gas revenue for margin was $756.6 million which does not include $12.7 million related to other gas operating revenues that is included gas operating revenues of $769.3 million.*

[2] *Included in 2005 purchased gas costs is a one-time true-up of previously reported gas cost of $5.0 million. See discussion under Operating Expenses-Purchased Gas.*

[3] *Gas margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

Gas margin increased $22.0 million for 2005 compared to 2004. Gas margin increased $17.3 million as a result of the gas general tariff rate increase of 3.5% effective March 4, 2005. In addition, therm sales increased 2.4% for 2005 compared to 2004, which provided $5.8 million to gas margin and changes in customer class usage provided $3.9 million to gas margin. Negatively impacting gas margin for 2005 was a $5.0 million one-time true-up of previously reported gas costs under the PGA mechanism. See further discussion under the section titled "Operating Expenses-Purchased Gas."

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE from 2004 to 2005.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 690.2	$ 628.9	$ 61.3	9.8 %
Commercial sales	629.0	581.0	48.0	8.3
Industrial sales	93.9	88.8	5.1	5.7
Other retail sales, including unbilled revenue	23.3	12.2	11.1	91.0
Total retail sales	1,436.4	1,310.9	125.5	9.6
Transportation sales	9.0	10.7	(1.7)	(15.9)
Sales to other utilities and marketers	105.0	56.5	48.5	85.8
Other	62.5	44.9	17.6	39.2
Total electric operating revenues	$ 1,612.9	$ 1,423.0	$ 189.9	13.3 %

Electric retail sales increased $125.5 million for 2005 compared to 2004 due primarily to rate increases related to the PCORC and the electric general rate case and increased retail customer usage. The PCORC and electric general rate case provided a combined additional $66.5 million to electric operating revenues for 2005 compared to 2004, which provided approximately $24.5 million in electric operating revenues. Retail electricity usage increased 588,645 MWh or 3.0% for 2005 compared to 2004. The increase in electricity usage was mainly the result of a 1.8% higher average number of customers served in 2005 compared to 2004.

During 2005, the benefits of the Residential and Small Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $189.0 million compared to $182.6 million for 2004. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers increased $48.5 million compared to 2004 primarily due to an increase of 569,613 MWh sold related to excess generation and energy available for sale on the wholesale market. This resulted primarily from normal streamflows for hydroelectric generation in the third quarter as compared to below normal streamflows that were expected. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions.

Other electric revenues increased $17.6 million for 2005 compared to 2004, primarily from the sale of excess non-core gas purchased for intended electric generation. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining costs.

The following electric rate changes were approved by the Washington Commission in 2005 and 2004:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Power Cost Only Rate Case	May 24, 2004	3.2 %	$ 44.1
Electric General Rate Case	March 4, 2005	4.1 %	57.7
Power Cost Only Rate Case	November 1, 2005	3.7 %	55.6

GAS OPERATING REVENUES

The table below sets forth changes in gas operating revenues for PSE from 2004 to 2005.

(Dollars in Millions) Twelve Months Ended December 31	2005	2004	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 592.4	$ 479.0	$ 113.4	23.7 %
Commercial sales	281.3	225.8	55.5	24.6
Industrial sales	48.3	38.8	9.5	24.5
Total retail sales	922.0	743.6	178.4	24.0
Transportation sales	13.3	13.0	0.3	2.3
Other	17.2	12.7	4.5	35.4
Total gas operating revenues	$ 952.5	$ 769.3	$ 183.2	23.8 %

Gas retail sales increased $178.4 million for 2005 compared to 2004 due to higher Purchased Gas Adjustment (PGA) mechanism rates in 2005, approval of a 3.5% general gas rate increase in the gas general rate case effective March 4, 2005 and higher customer gas usage. The Washington Commission approved PGA mechanism rate increases 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 2005, the effects of the PGA mechanism rate increases provided an increase of $123.8 million in gas operating revenues. In addition, the gas general rate increase provided an additional $17.3 million in gas operating revenue for 2005 compared to 2004. An increase of 3.1% in the average number of customers and lower temperatures in 2005 increased retail customer usage by 27.2 million therms or approximately $25.0 million in retail gas operating revenues.

The following gas rate adjustments were approved by the Washington Commission in 2005 and 2004:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
PGA	October 1, 2004	17.6 %	$ 121.7
Gas General Rate Case	March 4, 2005	3.5 %	26.3
PGA	October 1, 2005	14.7 %	121.6

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE from 2004 to 2005.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Purchased electricity	$ 860.4	$ 723.6	$ 136.8	18.9 %
Electric generation fuel	73.3	80.8	(7.5)	(9.3)
Residential exchange	(180.5)	(174.5)	(6.0)	(3.4)
Purchased gas	592.1	451.3	140.8	31.2
Utility operations and maintenance	333.3	291.2	42.1	14.5
Depreciation and amortization	241.6	228.6	13.0	5.7
Taxes other than income taxes	233.7	209.0	24.7	11.8
Income taxes	89.6	77.1	12.5	16.2

Purchased electricity expenses increased $136.8 million in 2005 compared to 2004 as a result of increased power purchases from higher customer usage and higher wholesale market prices offset by a reduction in the Tenaska disallowance related to the return on the Tenaska gas supply regulatory asset. The reduction of $39.3 million related to the Tenaska disallowance from 2004 included a February 23, 2005 Washington Commission order concerning PSE's compliance filing related to the PCA 2 period of July 1, 2003 through June 30, 2004. In its order, the Washington Commission determined that PSE was allowed to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003. These costs were reflected in the PCA mechanism, which resulted in a reduction in purchased electricity expense for 2005. Total purchased power for 2005 increased 1,336,501 MWh, or an 8.6% increase over 2004.

PSE's hydroelectric production and related power costs in 2005 and 2004 were negatively impacted by below-normal precipitation and reduced snow pack in the Pacific Northwest region. The January 4, 2006 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 2005 was 88% of normal, which approximates the total observed runoff for 2004. PSE cannot determine if lower than normal runoff will continue in future years nor what impact it may have on the amount of electricity that will need to be purchased. The February 3, 2006 Columbia Basin Runoff Summary indicated that the forecasted runoff above Grand Coulee Reservoir for January 2006 through July 2006 is 101% of normal.

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 regulated power portfolio through short-term and intermediate-term off-system physical purchases and sales and through other risk management techniques.

Electric generation fuel expense decreased $7.5 million in 2005 compared to 2004 primarily due to a $6.9 million charge recorded in 2004 related to a binding arbitration settlement between Western Energy Company and PSE. Excluding this settlement, electric generation fuel costs decreased $0.6 million related to overall lower cost of gas for combustion turbine units and cost of gas at those facilities totaling $5.6 million. The decrease in lower cost of gas was partially offset by an increase of the cost of coal of $5.0 million in 2005 compared to 2004 due to higher generation at Colstrip generating facilities of 56,797 MWhs. Costs associated with electric generation fuel are reflected in the PCA mechanism.

The reduction in electric generation fuel was also the result of the Hopkins Ridge wind generation facility beginning operations on November 27, 2005. Generation from the Hopkins Ridge generation facility does not include fuel expenses in its operation.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with BPA increased $6.0 million in 2005 compared to 2004 as a result of increased residential and small farm customer electric load. The residential exchange credit is a pass-through tariff item with a corresponding credit in electric operating revenue, thus it has no impact on electric margin or net income.

Purchased gas expenses increased $140.8 million in 2005 compared to 2004 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 receivable balance at December 31, 2005 and 2004 was $67.3 million and

$19.1 million, respectively. A receivable balance in the PGA mechanism reflects a current underrecovery of market gas cost through rates. For further discussion on PGA rates see Item 1 – Business - Gas Regulation and Rates.

In the second quarter 2005, PSE determined from a review of its PGA mechanism that a gas demand charge created during the settlement of the 2001 general rate case for a gas customer rate class had not been included within the parameters to calculate the costs under the PGA mechanism for rate recovery purposes. As a result, the balance of the PGA mechanism receivable has been overstated due to the exclusion of this charge over a 31-month period from September 1, 2002 to March 31, 2005. The PGA mechanism balance and gas costs for 2005 include an adjustment of $4.5 million to reflect the impact of the demand charge for previous years. This adjustment impacts the comparability of gas margin information and purchased gas expense for 2005 compared with 2004.

Utility operations and maintenance expense increased $42.1 million in 2005 compared to 2004 which includes an increase of $4.3 million related to low-income program costs that are passed-through in retail rates with no impact on earnings. As a result, the impact on net income from utility operations and maintenance for 2005 was an increase of $37.7 million. The increase for 2005 includes increases of $26.2 million related to higher gas distribution system expenses, planned maintenance costs for PSE-owned energy production facilities, electric distribution system costs, regulatory commission expense for rate cases and administrative costs. The production operation and maintenance increase for 2005 also includes a $1.5 million loss reserve associated with an arbitration panel's ruling in favor of the Muckleshoot Indian Tribe relating to the operation of a fish hatchery on the White River recorded in the second quarter 2005. These increases were partially offset by lower storm damage repair costs of $5.5 million for 2005 due to less severe weather and outages. Total storm damage costs for 2005 totaled $3.6 million compared to $9.1 million in 2004. PSE anticipates operation and maintenance expense to increase in future years as investments in new generating resources and energy delivery infrastructure are completed. The timing and amounts of increases will vary depending on when new generating resources come into service. During 2005, approximately $11.3 million of operation and maintenance expenses were not recovered in retail rates.

Depreciation and amortization expense increased $13.0 million in 2005 compared to 2004 due primarily to the effects of new generating and electric and gas distribution system plant placed in service in 2005. This includes a full year of depreciation expense related to $32.8 million for the Everett Delta gas transmission line placed in service in late 2004 and $80.8 million for the Frederickson 1 generating facility in April 2004. New plant placed in service in 2005 includes $170.9 million for the Hopkins Ridge wind project in November 2005. PSE anticipates depreciation expense will increase in future years as investments in new generating resources and energy delivery infrastructure are completed. During 2005, approximately $9.1 million of depreciation and amortization is unrecovered in rates.

Taxes other than income taxes increased $24.7 million in 2005 compared to 2004 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 $12.5 million in 2005 compared to 2004 as a result of higher taxable income and the non-recurrence of the one-time income tax benefit of $1.4 million in 2004 related to a 2001 tax audit.

OTHER INCOME AND INTEREST CHARGES

The table below sets forth significant changes in other income and interest charges for PSE from 2005 to 2004.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2005	2004	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 8.3	$ 4.4	$ 3.9	88.6 %
Interest charges	165.0	166.4	(1.4)	(0.8)

Other income increased $3.9 million (after-tax) in 2005 compared to 2004 primarily due to increases in the equity portion of allowance for funds used during construction and a decrease in long-term incentive plan costs due to not meeting the performance condition.

Interest charges decreased $1.4 million in 2005 compared to 2004 due to the redemption of $231 million of long-term debt with rates ranging from 3.40% to 6.93% in 2005. Also, in May 2005, PSE redeemed $42.5 million of PSE's 8.231% Capital Trust Preferred Securities (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet). These redemptions and resulting decreases in interest expense were partially offset by the issuance of $250 million and $150 million of long-term senior notes in May 2005 and October 2005, respectively. In addition, debt AFUDC credited to interest expense increased $4.1 million due to increased construction activity in 2005.

INFRASTRUX
2005 COMPARED TO 2004

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. Puget Energy intends to monetize its interest in InfrastruX through a sale. Puget Energy believes the planned disposal of InfrastruX meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements in 2005. Puget Energy is actively marketing InfrastruX and retained an investment banking firm to assist in the disposal of InfrastruX. To date, Puget Energy has not entered into a definitive agreement that would result in the sale of its investment in InfrastruX.

For 2005, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $9.5 million compared to a loss of $70.4 million (net of taxes and minority interest) for 2004. Included in the income for discontinued operations is a charge of $12.4 million for 2005 to adjust Puget Energy's carrying value of InfrastruX to its estimated fair value and for transaction costs. In accordance with SFAS No. 144, Puget Energy discontinued depreciation and amortization of InfrastruX's assets effective February 8, 2005. The following table summarizes Puget Energy's income from discontinued operations for 2005 and 2004:

(DOLLARS IN MILLIONS)	2005	2004
Income from operations reported by InfrastruX	$ 11.4	$ 6.8
Goodwill impairment	(13.9)	(91.2)
Tax provision on goodwill impairment	--	24.9
Net (loss) at InfrastruX	(2.5)	(59.5)
Goodwill impairment not recognized at Puget Energy	13.9	--
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	10.8	--
Puget Energy tax benefit (valuation allowance) from goodwill impairment	1.9	(18.0)
Carrying value adjustment to estimated fair value and transaction costs	(12.4)	--
Minority interest in income from discontinued operations	(2.2)	7.1
Income (loss) from discontinued operations	$ 9.5	$ (70.4)

InfrastruX reported strong financial results and cash flow in 2005 due to increased utility infrastructure sector spending. InfrastruX's operating revenue for 2005 and 2004 was $393 million and $370 million, respectively. Operation and maintenance costs in 2005 were $332.7 million compared to $320.2 million in 2004. InfrastruX recorded a non-cash goodwill impairment in 2005 of $13.9 million compared to $91.2 million non-cash goodwill impairment in 2004 under SFAS No. 142 "Goodwill and Other Intangible Assets," InfrastruX's bank and vendor debt under its credit agreements totaled $130.3 million at December 31, 2005 compared to $159.4 million at December 31, 2004. In May 2004, InfrastruX signed a three-year 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 borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $112 million was outstanding at December 31, 2005 and $131 million was outstanding at December 31, 2004. In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds on a sale will first be used to extinguish all InfrastruX debt outstanding.

In accordance with SFAS No. 144, Puget Energy has adjusted the carrying value of its investment in InfrastruX to the estimate of fair value, less cost to sell, at December 31, 2005. This estimate could change based on InfrastruX financial performance and market conditions in the utility constructions services sector. After reflecting a$12.4 million carrying value adjustment and charge for transaction costs in 2005, Puget Energy's equity investment in InfrastruX was $43.5 million at December 31, 2005 compared to $33.8 million at December 31, 2004. Puget Energy's carrying value under SFAS No. 144 as compared to the estimated fair value of its InfrastruX investment was not impacted by the non-cash goodwill impairment recorded by InfrastruX under SFAS No. 142 due to discontinued operations of InfrastruX. As a result, Puget Energy did not record the effects of the goodwill impairment under SFAS No. 142 in 2005.

InfrastruX's operations are dependent on a number of factors, including weather conditions, the availability of projects and capital to be spent on utility construction projects and key InfrastruX customer contractual relationships. As such, Puget Energy cannot determine the income or loss from InfrastruX's operations, nor any ultimate gain or loss upon completion of the sale of the entity. It is not anticipated that any funding will be needed from Puget Energy to maintain operations at InfrastruX or to complete the sale transaction.

PUGET SOUND ENERGY
2004 COMPARED TO 2003

ENERGY MARGINS

PSE uses the following margin information in reviewing its operations to determine whether PSE is collecting the appropriate amount of energy costs from its customers to allow operating cost recovery.

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

(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]	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:				
Electric generation fuel	(80.7)	(65.0)	(15.7)	(24.2)
Purchased electricity, net of sales to other utilities and marketers[2]	(660.3)	(635.2)	(25.1)	(4.0)
Total electric power costs[3]	(741.0)	(700.2)	(40.8)	(5.8)
Electric margin before PCA	647.0	630.7	16.3	2.6
Tenaska disallowance reserve	(26.0)	--	(26.0)	*
Power cost deferred under the PCA mechanism	19.1	3.5	15.6	*
Electric margin[4]	$ 640.1	$ 634.2	$ 5.9	0.9%

* *Percent change not applicable.*

[1] *For 2004, total electric revenue for margin was $1,333.1 million, which does not include $56.5 million in sales to other utilities and marketers and $33.4 million in other miscellaneous electric revenue included in electric operating revenues of $1,423.0 million. For 2003, total electric revenue for margin was $1,293.3 million, which does not include $82.8 million in sales to other utilities and marketers and $24.6 million in other miscellaneous electric revenues included in electric operating revenues of $1,400.7 million.*

[2] *For 2004, purchased electricity, net of sales to other utilities and marketers, was $660.3 million, excluding sales to other utilities and marketers of $56.5 million and including the Tenaska disallowance reserve of $36.5 million, the Tenaska reserve turnaround of $(10.5) and the power cost deferral under the PCA mechanism of $(19.1) million, purchased electricity was $723.6 million. For 2003, purchased electricity, net of sales to other utilities and marketers, was $635.2 million, excluding sales to other utilities and marketers of $82.8 million and the power cost deferral under the PCA mechanism of $(3.5) million, purchased electricity was $714.5 million.*

[3] *For 2004, total electric power costs were $741.0 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(174.5) million and unrealized net loss on derivative instruments of $(0.5) million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $629.3 million. For 2003, total electric power costs were $700.2 million, which includes electric generation fuel and purchased electricity, net of sales to other utilities and marketers (see note 2 above), but does not include the residential exchange credit of $(173.8) million. These amounts excluding sales of electricity to other utilities and marketers provide electric energy costs of $605.7 million.*

[4] *Electric margin does not include any allocation for amortization /depreciation expense or electric generation operations and maintenance expense.*

Electric margin increased $5.9 million in 2004 compared to 2003 due primarily to an increase in MWh 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. The PCORC rate increase of 3.2% 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 MWh 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.

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

	GAS MARGIN			
(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	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[1]	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[2]	$ 242.4	$ 244.2	$ (1.8)	(0.7)%

* *Percent change not applicable.*

[1] *For 2004, total gas revenue for margin was $756.6 million, which does not include $12.7 million related to other gas operating revenues that is included in gas operating revenues of $769.3 million. For 2003, total gas revenue for margin was $623.4 million, which does not include $10.8 million related to other gas operating revenues that is included gas operating revenues of $634.2 million.*

[2] *Gas margin does not include any allocation for amortization/depreciation expense or electric generation operations and maintenance expense.*

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 of 3.7%. Heating degree days decreased 2.3% in 2004 compared to 2003, which resulted in a 1.5% reduction in therm sales.

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
Other retail sales, including unbilled revenue	12.2	24.8	(12.6)	(50.8)
Total retail sales	1,310.9	1,272.7	38.2	3.0
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	44.9	33.7	11.2	33.2
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.

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
Total retail sales	743.6	609.6	134.0	22.0
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 and a 3.7% increase in the average number of customer served in 2004 compared to 2003. 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 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. 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 were negatively impacted by below-normal winter precipitation and snow pack in the Pacific Northwest region. The 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 2004 was 88% of normal, which compares to 87% of normal for 2003.

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 fuel expense for the Frederickson 1 generating facility, which was purchased and went into service in April 2004. Electric generation fuel for the Frederickson 1 facility amounted to $15.6 million in 2004. In addition, 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.

2004 also includes a loss reserve of $1.1 million 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. As approved by the Washington Commission the PGA mechanism allows PSE to recover expected gas costs, and deter, as a receivables liability, any gas costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including accrued interest.

Purchased gas expenses increased $124.2 million in 2004 compared to 2003 primarily due to an increase in PGA 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. Total storm damage costs for 2004 totaled $9.1 million compared to $5.9 million in 2003.

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

Conservation amortization decreased $10.8 million in 2004 compared to 2003 due to the conservation trust assets being fully amortized in September 2004.

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.

Income taxes increased $6.2 million in 2004 compared to 2003 due primarily to 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 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. In 2005, Puget Energy reported InfrastruX on a discontinued operations basis and as a result, loss from discontinued operations (net of taxes and minority interest) was $70.4 million in 2004 compared to income from discontinued operations of $1.8 million in 2003.

(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.

CAPITAL RESOURCES AND LIQUIDITY

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Puget Energy and Puget Sound Energy. The following are Puget Energy and Puget Sound Energy's aggregate consolidated (including PSE) contractual and commercial commitments as of December 31, 2005:

Puget Energy and Puget Sound Energy		Payments Due Per Period			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2006	2007-2008	2009-2010	2011 & Thereafter
Long-term debt including interest	$ 4,058.3	$ 227.1	$ 567.6	$ 606.8	$ 2,656.8
Short-term debt including interest	41.0	41.0	--	--	--
Junior subordinated debentures payable to a subsidiary trust including interest[1]	900.6	19.9	39.8	39.8	801.1
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	172.2	26.1	59.2	58.2	28.7
Non-cancelable operating leases	95.3	12.7	26.6	19.1	36.9
Fredonia combustion turbines lease [2]	60.8	4.4	8.5	8.2	39.7
Energy purchase obligations	5,299.8	1,144.9	1,838.9	1,255.4	1,060.6
Financial hedge obligations	43.2	24.7	18.5	--	--
Non-qualified pension and other benefits funding	51.7	4.4	11.1	10.2	26.0
Total contractual cash obligations	$ 10,724.8	$ 1,505.2	$ 2,570.2	$ 1,997.7	$ 4,651.7

Puget Energy. The following are Puget Energy's aggregate consolidated (including PSE) commercial commitments as of December 31, 2005:

Puget Energy		Amount of Commitment Expiration Per Period			
COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2006	2007-2008	2009-2010	2011 & THEREAFTER
Guarantees [3]	$ 112.0	$ --	$ 112.0	$ --	$ --
Liquidity facilities - available [4]	658.5	--	--	658.5	--
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 771.0	$ 0.5	$ 112.0	$ 658.5	$ --

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. Of the $150 million available to InfrastruX, $112.0 was outstanding at December 31, 2005.*

4 *At December 31, 2005, PSE had available a $500 million unsecured credit agreement expiring in April 2010 and a $200 million receivables securitization facility that expires in December 2010. At December 31, 2005, PSE had $41 million outstanding under its receivables securitization program. See "PSE Funding Receivables Securitization Facility" below for further discussion. The credit agreement provides credit support for letters of credit and commercial paper. At December 31, 2005, PSE had $0.5 million for an outstanding letter of credit and no commercial paper outstanding, thereby effectively reducing the available borrowing capacity under these liquidity facilities to $658.5 million.*

Puget Sound Energy. The following are PSE's aggregate commercial commitments as of December 31, 2005:

Puget Sound Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD 2006	2007-2008	2009-2010	2011 & Thereafter
Liquidity facilities - available [1]	$ 658.5	$ --	$ --	$ 658.5	$ --
Energy operations letter of credit	0.5	0.5	--	--	--
Total commercial commitments	$ 659.0	$ 0.5	$ --	$ 658.5	$ --

[1] *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., (Rainier Receivables) a wholly owned subsidiary of PSE, in December 2002 which expired December 20, 2005. 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 allowed Rainier Receivables to sell the receivables purchased from PSE to the third party. The amount of receivables sold by Rainier Receivables was not permitted to exceed $150 million at any time.

The receivables securitization facility was the functional equivalent of a revolving line of credit secured by receivables. In the event Rainier Receivables elected to sell the receivables under the Receivables Purchase Agreement, Rainier Receivables was 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 decline until Rainier Receivables elected to sell additional receivables to the purchasers.

During the years ended December 31, 2005 and 2004, Rainier Receivables sold a cumulative $351.9 million and $600.2 million of receivables, respectively. 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 the program.

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, 2005, PSE's outstanding balance under the lease was $54.0 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) and customer refundable contributions, were $588.6 million for 2005. Utility construction expenditures, excluding AFUDC and excluding new generation resources other than the Wild Horse project (which will be determined as the company proceeds through the least cost planning process) are anticipated to be the following in 2006 and 2007:

Capital Expenditure Projections (Dollars in Millions)	2006	2007
Energy delivery, technology and facilities	$ 454	$ 500
Wild Horse wind project	317	--
Total capital expenditures	771	500
Chelan contract payment[1]	89	--
Total expenditures	$ 860	$ 500

[1] *The Chelan contract payment represents a capacity reservation charge in conjunction with an impending new contract for hydroelectric power beginning 2011. PSE will seek an accounting order from the Washington Commission for rate base treatment of this payment and PSE anticipates it becoming approved as a regulatory asset.*

The proposed utility construction expenditures and any new generation resource expenditures that may be incurred are anticipated to be funded with a combination of cash from operations, 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

On November 27, 2005, PSE placed into service the Hopkins Ridge wind project. Hopkins Ridge is situated on 11,000 acres of remote, open wheat fields in southeastern Washington State. The Hopkins Ridge wind project features 83 Vestas 1.8 MW wind turbines providing up to 150 MW of nameplate capacity, or 52 average MW. The energy is delivered to PSE's service territory by BPA's transmission system via an interconnection. PSE has spent $181.7 million to date on the project. Included in this amount is the cost to acquire and construct the wind plant, to fund upgrades to the transmission systems of the Bonneville Power Administration and other regional transmission providers, and for development, transaction and financing costs.

On September 30, 2005, PSE completed the acquisition of the Wild Horse wind project in central Washington State from Horizon Wind Energy LLC and issued a notice to proceed with construction on the project. Simultaneously, PSE entered into an agreement with Vestas-American Wind Technology, Inc. (Vestas) to purchase and construct a total of 127 Vestas 1.8 MW wind turbines providing up to approximately 230 MW of capacity, or 73 average MW. The Wild Horse wind project is within PSE's service territory and, upon completion in late 2006, the energy will connect to an existing PSE transmission line. PSE anticipates spending up to approximately $380 million on the project. Included in the $380 million estimate is the cost to acquire land, wind turbines and other necessary assets, construction costs, and transaction, financing and contingency costs. Through December 31, 2005, PSE had spent $62.6 million on the Wild Horse project.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for 2005 was $255.8 million. During that period, $9.5 million was used for AFUDC, which reduced interest expense, and $88.1 million for payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $158.2 million or 26.9% of the $588.6 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for 2005. For 2004, cash generated from operations was $456.4 million. During that period, $5.4 million was used for AFUDC, which reduced interest expense, and $86.9 million was used for payment of dividends. Therefore, 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. The following table provides a summary of cash available and construction expenditures:

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED	2005	2004
Cash from operations	$ 255.8	$ 456.4
Less: Dividends paid	(88.1)	(86.9)
AFUDC	(9.5)	(5.4)
Cash available for construction expenditures	$ 158.2	$364.1
Construction and energy efficiency expenditures	$ 608.0	$ 434.2
Less: AFUDC	(9.5)	(5.4)
Cash received from refundable customer contributions	(9.9)	(13.4)
Net construction and energy efficiency expenditures	$ 588.6	$ 415.4

The overall cash generated from operating activities for 2005 decreased $200.6 million compared to 2004. The decrease was primarily the result of changes in the utilization of sales of accounts receivable under the accounts receivable securitization program which contributed $220.1 million to the decrease in cash generated from operations. Also contributing to the decrease was an increase in fuel and gas inventory amounting to $42.7 million, changes in the purchase gas receivable that contributed $17.2 million to the decrease, changes in deferred income taxes and taxes payable amounting to $91.8 million, and an increase of prepaid transmission amounting to $10.8 million. These decreases were partially offset by an increase in accounts payable balance of $94.3 million as compared to 2004, a decrease in prepaid items amounting to $8.4 million and funds received from a gas pipeline assignment amounting to $55.0 million.

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, 2005, PSE could issue:

- approximately $275 million of additional first mortgage bonds under PSE’s electric mortgage indenture based on approximately $458 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, 2005;
- approximately $223 million of additional first mortgage bonds under PSE’s gas mortgage indenture based on approximately $372 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, 2005;
- approximately $598 million of additional preferred stock at an assumed dividend rate of 7.0%; and
- approximately $400 million of unsecured long-term debt.

At December 31, 2005, PSE had approximately $3.7 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 any debt outstanding that would accelerate debt maturity upon a credit rating downgrade. However, a ratings downgrade could adversely affect the 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 borrowing costs 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 prompt 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 21, 2006, 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	Stable	Stable
Puget Energy		
Corporate credit/issuer rating	BBB-	Ba1

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

SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

On April 19, 2005, 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 $850 million of:

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

On May 18, 2005, PSE made an offer to repurchase all of PSE's 8.231% Capital Trust Preferred Securities (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet). The purpose of the tender offer was to help reduce interest costs by retiring higher cost debt. As a result of the tender offer, $42.5 million of the Capital Trust Preferred Securities were redeemed on June 2, 2005 at a 4% premium which totaled approximately $4.6 million. PSE may undertake future tender offers to reduce higher cost debt depending on future market opportunities.

In May 2005, PSE completed the issuance of $250 million of senior notes secured by first mortgage bonds, at a rate of 5.483%, due June 1, 2035. The net proceeds from the issuance of the senior notes of approximately $247.6 million were used to redeem $200 million of variable rate senior notes, which were redeemed at par in May 2005, and to repay a portion of PSE's short-term debt.

In October 2005, PSE completed the issuance of $150 million of senior notes secured by first mortgage bonds, at a rate of 5.197%, due October 1, 2015. The net proceeds from the issuance of the senior notes of approximately $149.0 million were used to repay a portion of PSE's short-term debt.

In November 2005, Puget Energy sold 15 million shares of common stock to Lehman Brothers Inc. for $312 million before underwriting discount. The net proceeds of approximately $309.8 million were invested in PSE and used to repay short-term debt incurred primarily to fund PSE's construction program.

Based on PSE's goal to become a more vertically integrated utility, it is expected that further issuances of debt, equity or a combination of the two will be necessary within one to two years to fund acquisitions of new generating resources. The structure, timing and amount of such financings are dependent on market conditions, projects available to be developed and financing needed at the time of any such acquisitions.

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.

PSE Credit Facilities. In May 2004, PSE entered into a three-year, $350 million unsecured credit agreement with a group of banks. In March 2005, PSE amended this credit agreement, increasing the total borrowing capacity from $350 million to $500 million, and extended the expiration date from June 2007 to April 2010. Under the terms of the credit agreement, PSE pays a floating interest rate on outstanding borrowings based either on the agent bank’s prime rate or on LIBOR plus a marginal rate based on PSE’s long-term credit rating at the time of borrowing. PSE pays a commitment fee on any unused portion of the credit agreement also based on long-term credit ratings of PSE. PSE also has a $200 million receivables securitization program which expires in December 2010. At December 31, 2005, PSE had available $500 million in the unsecured credit agreement and $159 million available under its receivable securitization facility, both of which provide credit support for outstanding commercial paper and outstanding letters of credit. At December 31, 2005, 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 $658.5 million.

In addition, PSE has an uncommitted $20 million unsecured credit agreement with a bank. PSE pays a varying interest rate on outstanding borrowings based on terms entered into at the time of the borrowings. There were no amounts outstanding under this credit agreement at December 31, 2005 or 2004.

PSE Funding Receivables Securitization Facility. In order to provide a source of liquidity to PSE at an attractive cost, PSE entered into a five-year Receivable Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned subsidiary of PSE, on December 20, 2005. The PSE Funding Agreement replaced the Rainier securitization facility, which terminated on December 20, 2005. Pursuant to the Receivables Sales Agreement, PSE sells all of its utility customer accounts receivable and unbilled utility revenues to PSE Funding. In addition, PSE Funding entered into a Loan and Servicing Agreement with PSE and two banks. The Loan and Servicing Agreement allows PSE Funding to use the receivables as collateral to secure short-term loans, not exceeding the lesser of $200 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers. The loans will be reported as short-term debt in the financial statements.

The PSE Funding receivables securitization facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. During 2005, PSE Funding borrowed a cumulative amount of $70.0 million secured by accounts receivable and had $41.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2005.

Puget Energy Credit Facility. Puget Energy had a $15 million credit agreement that was to expire in May 2006 with a bank. On February 1, 2005, Puget Energy reduced the borrowing capacity of this credit agreement to $5 million and on September 29, 2005 repaid all outstanding amounts and cancelled the agreement. Puget Energy had $5 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 $14.5 million (656,267 shares) in 2005 compared to $15.2 million (681,461 shares) in 2004. 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

IRS Notice of Proposed Adjustment. On July 12, 2005, Puget Energy received a notice of proposed adjustment (NOPA) from the Internal Revenue Service relating to a deduction in Puget Energy's 2003 tax return. The deduction relates to the receivable balance due from the California Independent System Operator. The NOPA states that the deduction was not valid for the 2003 tax year and would require repayment of approximately $14.5 million in tax. Puget Energy believes the deduction is valid and intends to vigorously defend the deduction; however, the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense could apply.

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 accumulated costs under the PCA mechanism for these excess costs. The increase in purchased electricity expense resulting from the disallowance totaled $4.1 million and $43.4 million in 2005 and 2004, respectively. The order also 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.

In August 2004 PSE filed the PCA 2 period compliance 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 $6.0 million related to the period July 1, 2003 through December 31, 2003.

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. Due to fluctuations in forward market prices of gas, the amount and timing of any potential disallowance related to Tenaska can change significantly day to day. The projected costs and projected benchmark costs for Tenaska as of December 31, 2005 based on current forward market gas prices are as follows:

(DOLLARS IN MILLIONS)	2006	2007	2008	2009	2010	2011
Projected Tenaska costs *	$ 258.0	$ 258.4	$ 240.5	$ 227.4	$ 214.6	$ 206.8
Projected Tenaska benchmark costs	175.3	174.8	182.9	189.9	197.4	205.6
Over (under) benchmark costs	$ 82.7	$ 83.6	$ 57.6	$ 37.5	$ 17.2	$ 1.2
Projected 50% disallowance based on Washington Commission methodology	$ 8.8	$ 7.7	$ 6.4	$ 4.8	$ 3.0	$ 0.6

* *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 that 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. If the refunds required by the formula would cause a seller to recover less than its actual costs for the refund period, FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In August 2005, PSE submitted its audited fuel cost allowance claim with the CAISO. That claim is currently pending. In September 2005, PSE submitted an additional cost filing claim pursuant to FERC's August 2005 order, demonstrating an overall revenue shortfall for sales into the California spot markets during the refund period after the mitigated market clearing price methodology was applied to its transactions. In January 2006, FERC issued its order on cost filings accepting PSE's cost filing claim subject to certain modifications and the utilization of final CAISO data. PSE does not agree with all of FERC's rulings and will seek rehearing of some of FERC's determinations. Once the CAISO receives updated cost offset filings from sellers, including PSE, it will continue efforts to prepare revised settlement statements for spot market sales to California during the refund period. Thus, PSE's ability to recover all or a part of its costs remains uncertain at this time. Global settlements have been announced and/or approved, including settlements between the California Parties and Williams, Duke, El Paso, Mirant, Dynegy, Enron, Reliant and

Public Service Company of Colorado. These settlements, supported by a statement from FERC chairman Joseph Kelliher, may suggest that the process momentum toward settlement in the California Refund Proceedings is increasing.

Many of the numerous orders that FERC issued in Docket No. EL00-95 are on appeal before the United States Court of Appeals for the Ninth Circuit. Some of those issues have been consolidated as a result of a case management conference conducted on September 21, 2004. The Ninth Circuit ordered on October 22, 2004 that briefing proceed in two rounds. The first round was 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; and (3) which categories of transactions are subject to refunds. 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 unjust and unreasonable. The court heard oral argument on April 12 and 13, 2005. On September 6, 2005, the court ruled that, as to the first issue, FERC does not have refund authority over wholesale electric sales made by governmental utilities. No decision has been issued on the other issues argued in April 2005. The order remanding the proceeding back to FERC and the time for seeking rehearing in the governmental utilities case has been extended until 45 days after a decision on the other issues identified above. The parties await a decision from the court on the remaining two other issues. Procedures will be established for the remaining issues, if necessary, after the court's disposition of the first round of issues.

b. ***CAISO Receivable***. At December 31, 2005, PSE had a net receivable totaling $21.3 million in connection with wholesale sales in 2000 to the California Independent System Operator (CAISO) and counterparties where payment to PSE was conditioned on the counterparties being paid by the California Power Exchange. In August 2005, PSE submitted a Fuel Cost Adjustment Claim for $3.4 million related to sales in 2000 to the CAISO, pursuant to FERC's California refund proceeding.

Pursuant to an order issued by FERC in August 2005, PSE also submitted a Portfolio Cost Claim in September 2005 for $9.3 million to the CAISO. On January 26, 2006, FERC issued its order on Cost Filings accepting PSE's cost filing subject to certain modifications, which appear to have the effect of reducing PSE's Portfolio Claim substantially, possibly to zero. However, the Company does not believe the claim will be reduced below the $21.3 million receivable. PSE does not agree with all of FERC's rulings and may seek rehearing. PSE's ability to recover all or a portion of these claims is uncertain at the present time.

Based upon FERC orders, PSE has determined a range related to its CAISO receivable to be between $21.3 million (PSE's net receivable balance) and $25.3 million including interest on its past due receivables as of December 31, 2005.

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 complete and the parties await a date for oral argument.

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. Oral argument is scheduled to take place on March 7, 2006.

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. Both cases were dismissed on the grounds that FERC has the exclusive jurisdiction over plaintiff's claims. On March 10, 2005, Wah Chang filed a notice of appeal to the United States Court of Appeals for the Ninth Circuit. Opening and response briefs were filed and the appeal has been consolidated with Wah Chang's complaint against energy marketers. The parties await a date for oral argument.

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.

   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 sought, 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 sought indemnification, declaratory relief 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.

   On July 22, 2005, the court considered a proposed settlement that would resolve all claims against the Duke parties and on December 14, 2005, the court issued a judgment and order approving the Duke settlement. In August 2005, Reliant also announced it had reached a settlement that would result in the dismissal of the Master Complaint. The court issued a judgment and order preliminarily approving the Reliant settlement on January 6, 2006. Hearing on final approval for the Reliant settlement is scheduled for April 2006. Duke and Reliant both filed stipulated requests for dismissal of the cross-complaints against defendants, including PSE. The dismissals will become final only once the court's orders granting final approval of the Duke and Reliant settlements become final.

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, which vary little from year-to-year. 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 or upon the sale of assets. 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	$0.5	$0.7

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, 2005 in the amount of $674.3 million and $241.9 million, respectively, and regulatory assets and liabilities of $645.3 million and $185.7 million, respectively, at December 31, 2004. 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 energy portfolio management 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 2005, 2004 and 2003, qualified pension income of $2.6 million, $8.0 million and $12.9 million, respectively, was recorded in the financial statements. Of these amounts, approximately 63.0%, 63.3% and 67.0% offset utility operations and maintenance expense in 2005, 2004 and 2003, respectively, and the remaining amounts were capitalized. Qualified pension expense is expected to be $0.3 million in 2006 as a result of lower than expected returns on pension assets.

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, mortality 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 its projected benefit obligation. The Company has selected an expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. During 2005, PSE made no cash contributions to the qualified defined benefit plan and expects to make no contributions in 2006.

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

(Dollars in Thousands)	Change in Assumption	Impact on Projected Benefit Obligation increase (decrease) Pension Benefits	Impact on Projected Benefit Obligation increase (decrease) Other Benefits	Impact on 2005 Pension Income increase (decrease) Pension Benefits	Impact on 2005 Pension Income increase (decrease) Other Benefits
Increase in discount rate	50 basis points	$(21,267)	$(2,820)	$ 1,964	$ 388
Decrease in discount rate	50 basis points	23,376	3,015	(2,133)	(332)
Increase in return of plan assets	50 basis points	*	*	2,299	80
Decrease in return on plan assets	50 basis points	*	*	(2,299)	(80)

**Calculation not applicable.*

Intangibles (Puget Energy Only). Puget Energy performs an annual impairment review under SFAS No. 142, "Goodwill and Other Intangible Assets," 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, 2005 and 2004 was $43.9 million and $43.5 million, respectively. Intangible assets have not been impaired and the balance at December 31, 2005 and 2004 was $14.4 million and $16.7 million, respectively.

Impairment of Long-Lived Assets (Puget Energy Only). Puget Energy 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, including assets to be disposed, are impaired and how losses, if any, should be recognized. Puget Energy believes that the present value of the estimated future cash inflows from the use and eventual disposition of long-lived assets are sufficient to recover their carrying values.

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, was $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, 2005, such receivables 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, 2005 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 their award date. SFAS No. 123R was originally effective for interim reporting periods beginning after June 15, 2005. However, on April 14, 2005, the Securities and Exchange Commission delayed implementation of SFAS No. 123R to annual reporting periods beginning after June 15, 2005, which will be January 1, 2006 for the Company. The Company had adopted the fair value provisions of SFAS No. 123 "Accounting for Stock Based Compensation" in January 2003. The Company adopted SFAS No. 123R on January 1, 2006.

The Company does not expect the expense for stock options computed in accordance with SFAS No. 123R to be materially different than the expense computed under SFAS No. 123. SFAS No. 123R requires that the total impact of adopting the standard to be accounted for as a cumulative effect of an accounting change net of tax.

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. For the period July 1, 2006 through December 31, 2006, the sharing bands will be half of the annual bands without a cap for excess power costs and beginning January 1, 2007, the PCA mechanism will provide sharing of costs and benefits that are graduated over four levels for each calendar year without a maximum cap for excess power costs.

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 Energy Management Committee, which is composed of Company officers, provides policy-level and strategic direction for management of the energy portfolio. The Finance and Budget 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 portfolio 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 portfolio 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 portfolio 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 Energy Management Committee. The Company's programmatic hedging strategies may be modified, as approved by the Energy Management Committee, in response to market fundamental information and trends. 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, 2005, 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 process employing stochastic differential equations using market volatilities and prices as inputs to create various commodity forward curves. These simulated forward curves are then used to value various option contracts across a spectrum of commodities.

At December 31, 2005, the Company had a short-term asset of $2.2 million and a short-term liability of $0.8 million, primarily as a result of de-designating gas financial contracts. These contracts were related to electric generation that was no longer probable. During 2005, the Company recorded a decrease in earnings for the change in the market value of derivative instruments not meeting the normal purchase normal sale exception nor cash flow hedging criteria under SFAS No. 133 of $0.5 million compared to an increase in earnings of $0.5 million for 2004. The decrease in 2005 primarily related to the reversal of prior period de-designated gas financial hedges for electric generation.

At December 31, 2005, the Company had a short-term asset of $37.9 million and a long term asset of $28.5 million related to energy contracts designated as cash flow hedges that represent forward financial purchases of gas supply for electric generation of PSE-owned electric plants in future periods. These contracts were designated as qualifying cash flow hedges and a corresponding unrealized gain of $43.2 million, net of tax, was recorded in other comprehensive income. Of the amount in other comprehensive income, 99% of the unrealized mark-to-market gain (or $6.3 million) for the period January 2006 through April 2006 has been reclassified out of other comprehensive income to a deferred account in accordance with SFAS No. 71 due to the Company expecting to exceed the $40 million cap for the PCA mechanism. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses, when these de-designated cash flow hedges are settled, are recognized in energy costs and are included as part of the PCA mechanism. Due to high forward market prices at the end of December 2005, unrealized gains have resulted in cash flow hedge assets for the period.

At December 31, 2005, the Company also had a short-term asset of $34.7 million and a short-term liability of $9.0 million related to the cash flow hedge of gas contracts to serve natural gas customers. In 2005, natural gas prices increased partly due to disruptions in global supply therefore; existing gas financial hedges showed unrealized gains when marked to the higher market prices. 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. All increases and decreases in the cost of natural gas supply are passed on to customers with the PGA mechanism. As the gains and losses on the cash flow hedges are realized in future periods, they will be recorded as gas costs under the PGA mechanism.

A hypothetical 10% decrease in the market prices of natural gas and electricity would decrease the fair value of qualifying cash flow hedges by $13.5 million and would decrease current earnings for those contracts marked-to-market in earnings by an immaterial amount due to the PCA mechanism.

ENERGY DERIVATIVE CONTRACTS GAIN/(LOSS) (DOLLARS IN MILLIONS)	AMOUNTS
Fair value of contracts outstanding at December 31, 2004	$ 14.9
Contracts realized or otherwise settled during 2005	5.9
Changes in fair values of derivatives	72.8
Fair value of contracts outstanding at December 31, 2005	$ 93.6

SOURCE OF FAIR VALUE (DOLLARS IN MILLIONS)	FAIR VALUE OF CONTRACTS WITH SETTLEMENT DURING YEAR 2006	2007-2008	2009-2010	2011 AND THEREAFTER	TOTAL FAIR VALUE
Prices actively quoted	$ 65.2	$ 19.8	$ --	$ --	$ 85.0
Prices provided by other external sources	--	8.6	--	--	8.6
Prices based on models and other valuation methods	$ 65.2	$ 28.4	$ --	$ --	$ 93.6

CREDIT RISK

The Company is exposed to credit risk primarily through buying and selling electricity and gas to serve customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, exposure monitoring, and exposure mitigation.

It is possible that extreme volatility in energy commodity prices could cause the Company to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2005, approximately 92% of the counterparties comprising the sources of our energy portfolio are rated at least investment grade by the major rating agencies and 8% are either rated below investment grade or are not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

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 on fixed rate debt as of December 31, 2005 or 2004, however from time to time the Company may enter into treasury lock or forward starting swap contracts to hedge interest rate exposure related to anticipated debt issuance. The carrying amounts and the fair values of Puget Energy's debt instruments are:

	2005		2004	
(DOLLARS IN MILLIONS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial liabilities:				
Short-term debt	$ 41.0	$ 41.0	$ 8.3	$ 8.3
Long-term debt – fixed-rate[1]	2,264.4	2,416.6	2,051.4	2,194.8
Long-term debt – variable-rate[1]	--	--	200.0	199.9

[1] *PSE's carrying value and fair value of fixed-rate long-term debt in 2005 was the same as Puget Energy's debt. 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.*

In the second quarter 2005, the Company settled its two treasury lock contracts that originated in August 2004. The purpose of the treasury lock contracts was to hedge exposure to interest rate volatility for a debt offering of $250.0 million that was completed in May 2005. Since treasury interest rates related to the hedged debt decreased from the date of issuance of the treasury lock instruments, PSE paid the counterparties $35.3 million for the change in bond value when the contracts were settled. In addition, the bonds issued associated with the treasury lock instruments had a correspondingly lower interest rate since treasury rates decreased from the date of issuance of the treasury lock instruments. The treasury lock contracts were designated and documented 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. In the second quarter 2005, the settlement loss on these instruments amounted to $23.0 million, after-tax, and was recorded as a loss in other comprehensive income. In accordance with SFAS No. 133, this loss is being amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued at an annual rate of approximately $1.2 million pre-tax. The ending balance in other comprehensive income related to the treasury lock contracts at December 31, 2005 was a loss of $22.5 million after-tax and accumulated amortization.

In the second quarter 2005, the Company entered into two forward starting swap contracts to hedge against interest rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting swap 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 designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decreased related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in bond value. These swap contracts were designated under SFAS No. 133 criteria as cash flow hedges. All financial hedge contracts of this type are reviewed by senior management and presented to the Finance and Budget Committee of the Board of Directors, and are approved prior to execution. At December 31, 2005, the unrealized gain associated with the two swap contracts was $0.1 million after-tax and is included in other comprehensive income. The forward starting swap contracts will settle completely in 2006. A hypothetical 10% decrease in the interest rate of a 30-year Treasury note would result in a loss of $10.1 million net of tax in other comprehensive income. The counterparties calculate the current market value for the existing forward swap positions based on market interest rates and swap rates as of December 31, 2005.

TREASURY LOCK CONTRACTS GAIN/(LOSS) (DOLLARS IN MILLIONS)	AMOUNTS
Fair value of contracts outstanding at December 31, 2004	$ (17.4)
Contracts realized or otherwise settled during 2005	35.3
Changes in fair values of derivatives	(17.8)
Fair value of contracts outstanding at December 31, 2005	$ 0.1

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 Chairman of the Board, 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 Corporate Ethics and Compliance 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 the Chief Ethics and Compliance 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.

Management is confident that the internal control structure is operating effectively and will allow the Company to meet the requirements under Section 404 of the Sarbanes-Oxley Act of 2002.

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 audit conducted in accordance with auditing standards prescribed by the Public Company Accounting Oversight Board, 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.

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
Chairman, President and Chief Executive Officer	*Senior Vice President Finance and Chief Financial Officer*	*Vice President, 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 integrated audits of Puget Energy, Inc.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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." As described in Note 2 to the consolidated financial statements, effective December 31, 2005, the Company changed its method of accounting for asset retirement activities that are conditional on a future event as required by FIN 47 "Accounting for Conditional Asset Retirement Obligations" which interprets Statement of Financial Accounting Standards No. 143.

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, 2005 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, 2005, based on 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
February 27, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Puget Sound Energy, Inc.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 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 Sound Energy, Inc. and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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." As described in Note 2 to the consolidated financial statements, effective December 31, 2005, the Company changed its method of accounting for asset retirement activities that are conditional on a future event as required by FIN 47 "Accounting for Conditional Asset Retirement Obligations" which interprets Statement of Financial Accounting Standards No. 143.

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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
February 27, 2006

Puget Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2005	2004	2003
Operating revenues:			
Electric	$ 1,612,869	$ 1,423,034	$ 1,400,743
Gas	952,515	769,306	634,230
Other	7,826	6,537	6,043
Total operating revenues	2,573,210	2,198,877	2,041,016
Operating expenses:			
Energy costs:			
Purchased electricity	860,422	723,567	714,469
Electric generation fuel	73,318	80,772	64,999
Residential exchange	(180,491)	(174,473)	(173,840)
Purchased gas	592,120	451,302	327,132
Unrealized (gain) loss on derivative instruments	472	(526)	106
Utility operations and maintenance	333,256	291,232	289,702
Other operations and maintenance	2,657	2,326	1,548
Depreciation and amortization	241,634	228,566	220,087
Conservation amortization	24,308	22,688	33,458
Taxes other than income taxes	233,742	208,989	194,857
Income taxes	88,609	76,756	70,775
Total operating expenses	2,270,047	1,911,199	1,743,293
Operating income	303,163	287,678	297,723
Other income (deductions):			
Other income	8,309	4,362	1,587
Interest charges:			
AFUDC	9,493	5,420	3,343
Interest expense	(174,591)	(171,959)	(181,830)
Mandatorily redeemable securities interest expense	(91)	(91)	(1,072)
Preferred stock dividends of subsidiary	--	--	(5,151)
Net income from continuing operations	146,283	125,410	114,600
Income (loss) from discontinued segment (net of tax)	9,514	(70,388)	1,766
Net income before cumulative effect of accounting change	155,797	55,022	116,366
Cumulative effect of implementation of accounting change (net of tax)	71	--	169
Net income	$ 155,726	$ 55,022	$ 116,197
Common shares outstanding weighted average (in thousands)	102,570	99,470	94,750
Diluted shares outstanding weighted average (in thousands)	103,111	99,911	95,309
Basic earnings per common share before cumulative effect from accounting change	$ 1.43	$ 1.26	$ 1.21
Basic earnings per common share from discontinued operations	0.09	(0.71)	0.02
Cumulative effect from accounting change	--	--	--
Basic earnings per common share	$ 1.52	$ 0.55	$ 1.23
Diluted earnings per common share before cumulative effect from accounting change	$ 1.42	$ 1.26	$ 1.20
Diluted earnings per common share from discontinued operations	0.09	(0.71)	0.02
Cumulative effect from accounting change	--	--	--
Diluted earnings per common share	$ 1.51	$ 0.55	$ 1.22

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

Puget Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2005	2004
Utility plant:		
Electric plant	$ 4,802,363	$ 4,389,882
Gas plant	1,991,456	1,881,768
Common plant	439,599	409,677
Less: Accumulated depreciation and amortization	(2,602,500)	(2,452,969)
Net utility plant	4,630,918	4,228,358
Other property and investments	157,321	157,670
Current assets:		
Cash	16,710	12,955
Restricted cash	1,047	1,633
Accounts receivable, net of allowance for doubtful accounts	294,509	137,659
Secured pledged accounts receivable	41,000	--
Unbilled revenues	160,207	140,391
Purchased gas adjustment receivable	67,335	19,088
Materials and supplies, at average cost	36,491	31,683
Fuel and gas inventory, at average cost	91,058	65,895
Unrealized gain on derivative instruments	75,037	14,791
Prepayments and other	7,596	6,858
Deferred income taxes	--	1,415
Current assets of discontinued operations	107,434	110,922
Total current assets	898,424	543,290
Other long-term assets:		
Regulatory asset for deferred income taxes	129,693	127,252
Regulatory asset for PURPA buyout costs	191,170	211,241
Unrealized gain on derivative instruments	28,464	21,315
Power cost adjustment mechanism	18,380	--
Other	388,468	401,795
Long-term assets of discontinued operations	167,113	160,298
Total other long-term assets	923,288	921,901
Total assets	$ 6,609,951	$ 5,851,219

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	2005	2004
Capitalization:		
(See Consolidated Statements of Capitalization)		
Common equity	$ 2,027,047	$ 1,622,276
Total shareholders' equity	2,027,047	1,622,276
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	237,750	280,250
Long-term debt	2,183,360	2,069,360
Total redeemable securities and long-term debt	2,422,999	2,351,499
Total capitalization	4,450,046	3,973,775
Minority interest in discontinued operations	6,816	4,648
Current liabilities:		
Accounts payable	346,490	226,478
Short-term debt	41,000	--
Current maturities of long-term debt	81,000	31,000
Accrued expenses:		
Taxes	112,860	81,315
Salaries and wages	15,034	13,829
Interest	31,004	29,005
Unrealized loss on derivative instruments	9,772	26,581
Deferred income tax	10,968	--
Tenaska disallowance reserve	--	3,156
Other	35,694	34,918
Current liabilities of discontinued operations	55,791	51,892
Total current liabilities	739,613	498,174
Long-term liabilities:		
Deferred income taxes	738,809	795,291
Unrealized loss on derivative instruments	--	385
Other deferred credits	513,023	395,236
Long-term liabilities of discontinued operations	161,644	183,710
Total long-term liabilities	1,413,476	1,374,622
Commitments and contingencies		
Total capitalization and liabilities	$ 6,609,951	$ 5,851,219

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

Puget Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2005	2004
Common equity:		
Common stock $0.01 par value, 250,000,000 shares authorized, 115,695,463 and 99,868,368 shares outstanding at December 31, 2005 and 2004	$ 1,157	$ 999
Additional paid-in capital	1,948,975	1,621,756
Earnings reinvested in the business	69,407	13,853
Accumulated other comprehensive income (loss) – net of tax	7,508	(14,332)
Total common equity	2,027,047	1,622,276
Preferred stock subject to mandatory redemption – cumulative – $100 par value: *		
4.84% series –150,000 shares authorized, 14,583 shares outstanding at December 31, 2005 and 2004	1,458	1,458
4.70% series –150,000 shares authorized, 4,311 shares outstanding at December 31, 2005 and 2004	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	237,750	280,250
Long-term debt:		
First mortgage bonds and senior notes	2,102,500	1,933,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Other notes	--	5,000
Long-term debt due within one year	(81,000)	(31,000)
Total long-term debt excluding current maturities	2,183,360	2,069,360
Total capitalization	$ 4,450,046	$ 3,973,775

** 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, 2005, 2004 & 2003	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
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
Net income	--	--	--	155,726	--	155,726
Common stock dividend declared	--	--	--	(100,172)	--	(100,172)
Common stock issued:						
New issuance	15,009,991	150	309,744	--	--	309,894
Dividend reinvestment plan	656,267	6	14,545	--	--	14,551
Employee plans	160,837	2	2,930	--	--	2,932
Other comprehensive loss	--	--	--	--	21,840	21,840
Balance at December 31, 2005	115,695,463	$ 1,157	$1,948,975	$ 69,407	$ 7,508	$2,027,047

Puget Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2005	2004	2003
Net income	$ 155,726	$ 55,022	$ 116,197
Other comprehensive income, net of tax at 35%:			
Unrealized holding losses on marketable securities during the period	--	--	(45)
Reclassification adjustment for realized gains on marketable securities included in net income	--	--	(1,518)
Foreign currency translation adjustment	(91)	275	80
Minimum pension liability adjustment	925	157	(1,122)
Net unrealized gains on derivative instruments during the period	49,770	6,820	8,576
Reversal of net unrealized (gains) losses on derivative instruments settled during the period	(19,164)	(10,418)	181
Loss from settlement of cash flow hedge contracts	(22,960)	--	--
Amortization of cash flow hedge contracts to earnings	455	--	--
Deferral of cash flow hedges related to power cost adjustment mechanism	12,905	(3,103)	(16,055)
Other comprehensive income (loss)	21,840	(6,269)	(9,903)
Comprehensive income	$ 177,566	$ 48,753	$ 106,294

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	2005	2004	2003
Operating activities:			
Net income	$ 155,726	$ 55,022	$ 116,197
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	241,634	246,842	236,866
Deferred income taxes and tax credits – net	(56,852)	72,702	57,470
Power cost adjustment mechanism	(18,380)	3,605	(3,605)
Gain from sale of securities	--	--	(2,889)
InfrastruX goodwill impairment	--	91,196	--
InfrastruX carrying value impairment adjustment	7,269	--	--
Net unrealized (gain) loss on derivative instruments	472	(526)	106
Other (including conservation amortization)	6,072	6,498	22,288
Cash collateral received from (returned to) energy suppliers	15,700	6,320	(21,425)
Gas pipeline capacity assignment	55,000	--	--
BPA prepaid transmission	(10,750)	--	--
Increase (decrease) in residential exchange program	(4,941)	1,668	(25,989)
Pension plan funding	--	--	(26,521)
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(217,861)	2,218	37,769
Materials and supplies	(4,945)	(39,740)	(13,322)
Fuel and gas inventory	(25,163)	17,512	(1,405)
Prepayments and other	273	(8,159)	(738)
Purchased gas receivable / liability	(48,246)	(31,073)	(71,826)
Accounts payable	119,416	25,163	6,464
Taxes payable	38,047	247	13,405
Tenaska disallowance reserve	(3,156)	3,156	--
Accrued expenses and other	6,496	3,709	(4,939)
Net cash provided by operating activities	255,811	456,360	317,906
Investing activities:			
Construction and capital expenditures – excluding equity AFUDC	(583,594)	(409,403)	(285,510)
Energy efficiency expenditures	(24,428)	(24,852)	(18,579)
Restricted cash	586	905	20,106
Cash received from sale of securities	--	--	3,161
Cash proceeds from property sales	24,291	1,315	2,075
Refundable cash received for customer construction projects	9,869	13,424	5,045
Investments by InfrastruX	--	--	(10,659)
Other	5,906	432	76
Net cash used by investing activities	(567,370)	(418,179)	(284,285)
Financing activities:			
Decrease in short-term debt – net	36,512	(5,596)	(33,402)
Dividends paid	(88,071)	(86,873)	(86,671)
Issuance of common stock	317,607	5,413	106,659
Issuance of bonds and notes	400,000	343,841	319,497
Redemption of preferred stock	--	--	(60,000)
Redemption of mandatorily redeemable preferred stock	--	--	(41,273)
Redemption of trust preferred stock	(42,500)	--	(19,750)
Redemption of bonds and notes	(260,615)	(308,708)	(357,510)
Settlement of interest rate derivatives	(35,323)	--	--
Issuance costs and other	(12,928)	6,032	(10,359)
Net cash provided (used) by financing activities	314,682	(45,891)	(182,809)
Increase (decrease) in cash from net income	3,123	(7,710)	(149,188)
Cash at beginning of year	19,771	27,481	176,669
Cash at end of year	$ 22,894	$ 19,771	$ 27,481
Supplemental Cash Flow Information:			
Cash payments for:			
Interest (net of capitalized interest)	$ 182,054	$ 182,419	$ 192,845
Income taxes (net of refunds)	126,807	(1,232)	(2,777)

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	2005	2004	2003
Operating revenues:			
Electric	$ 1,612,869	$ 1,423,034	$ 1,400,743
Gas	952,515	769,306	634,230
Other	7,826	6,537	6,043
Total operating revenues	2,573,210	2,198,877	2,041,016
Operating expenses:			
Energy costs:			
Purchased electricity	860,422	723,567	714,469
Electric generation fuel	73,318	80,772	64,999
Residential exchange	(180,491)	(174,473)	(173,840)
Purchased gas	592,120	451,302	327,132
Unrealized (gain) loss on derivative instruments	472	(526)	106
Utility operations and maintenance	333,256	291,232	289,702
Other operations and maintenance	1,304	1,342	1,203
Depreciation and amortization	241,634	228,566	220,087
Conservation amortization	24,308	22,688	33,458
Taxes other than income taxes	233,742	208,989	194,857
Income taxes	89,629	77,177	70,939
Total operating expenses	2,269,714	1,910,636	1,743,112
Operating income	303,496	288,241	297,904
Other income (deductions):			
Other income	8,309	4,362	1,587
Interest charges:			
AFUDC	9,493	5,420	3,343
Interest expense	(174,367)	(171,740)	(181,707)
Mandatorily redeemable securities interest expense	(91)	(91)	(1,072)
Net income before cumulative effect of accounting change	146,840	126,192	120,055
Cumulative effect of implementation of accounting change (net of tax)	71	--	169
Net income	146,769	126,192	119,886
Less: preferred stock dividends accrual	--	--	5,151
Net income for common stock	$ 146,769	$ 126,192	$ 114,735

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	2005	2004
Utility plant:		
Electric plant	$ 4,802,363	$ 4,389,882
Gas plant	1,991,456	1,881,768
Common plant	439,599	409,677
Less: Accumulated depreciation and amortization	(2,602,500)	(2,452,969)
Net utility plant	4,630,918	4,228,358
Other property and investments	157,321	157,670
Current assets:		
Cash	16,709	12,955
Restricted cash	1,047	1,633
Accounts receivable, net of allowance for doubtful accounts	299,938	138,792
Secured pledged accounts receivable	41,000	--
Unbilled revenues	160,207	140,391
Purchased gas adjustment receivable	67,335	19,088
Materials and supplies, at average cost	36,491	31,683
Fuel and gas inventory, at average cost	91,058	65,895
Unrealized gain on derivative instruments	75,037	14,791
Prepayments and other	7,023	6,247
Deferred income taxes	--	1,415
Total current assets	795,845	432,890
Other long-term assets:		
Regulatory asset for deferred income taxes	129,693	127,252
Regulatory asset for PURPA buyout costs	191,170	211,241
Unrealized gain on derivative instruments	28,464	21,315
Power cost adjustment mechanism	18,380	--
Other	388,009	401,030
Total other long-term assets	755,716	760,838
Total assets	$ 6,339,800	$ 5,579,756

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	2005	2004
Capitalization:		
(See Consolidated Statements of Capitalization):		
Common equity	$ 1,986,621	$ 1,592,433
Total shareholder's equity	1,986,621	1,592,433
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	237,750	280,250
Long-term debt	2,183,360	2,064,360
Total redeemable securities and long-term debt	2,422,999	2,346,499
Total capitalization	4,409,620	3,938,932
Current liabilities:		
Accounts payable	346,490	229,747
Short-term debt	41,000	--
Current maturities of long-term debt	81,000	31,000
Accrued expenses:		
Taxes	111,900	81,634
Salaries and wages	15,034	13,829
Interest	31,004	29,005
Unrealized loss on derivative instruments	9,772	26,581
Deferred income taxes	10,968	--
Tenaska disallowance reserve	--	3,156
Other	30,932	34,918
Total current liabilities	678,100	449,870
Long-term liabilities:		
Deferred income taxes	739,162	795,392
Unrealized loss on derivative instruments	--	385
Other deferred credits	512,918	395,177
Total long-term liabilities	1,252,080	1,190,954
Commitments and contingencies		
Total capitalization and liabilities	$ 6,339,800	$ 5,579,756

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	2005	2004
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	924,154	609,467
Earnings reinvested in the business	196,248	138,678
Accumulated other comprehensive income (loss) – net of tax	7,181	(14,750)
Total common equity	1,986,621	1,592,433
Preferred stock subject to mandatory redemption - cumulative		
$100 par value:*		
4.84% series – 150,000 shares authorized,		
14,583 shares outstanding at December 31, 2005 and 2004	1,458	1,458
4.70% series – 150,000 shares authorized,		
4,311 shares outstanding at December 31, 2005 and 2004	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	237,750	280,250
Long-term debt:		
First mortgage bonds and senior notes	2,102,500	1,933,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Long-term debt due within one year	(81,000)	(31,000)
Total long-term debt excluding current maturities	2,183,360	2,064,360
Total capitalization	$ 4,409,620	$ 3,938,932

**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 SHAREHOLDER'S EQUITY

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31, 2005, 2004 & 2003	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
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
Net income	--	--	--	146,769	--	146,769
Common stock dividend declared	--	--	--	(89,199)	--	(89,199)
Investment received from Puget Energy	--	--	314,687	--	--	314,687
Other comprehensive income	--	--	--	--	21,931	21,931
Balance at December 31, 2005	85,903,791	$859,038	$924,154	$196,248	$ 7,181	$1,986,621

Puget Sound Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2005	2004	2003
Net income	$ 146,769	$ 126,192	$ 119,886
Other comprehensive income, net of tax at 35%:			
Unrealized holding losses on marketable securities during the period	--	--	(45)
Reclassification adjustment for realized gains on marketable securities included in net income	--	--	(1,518)
Minimum pension liability adjustment	925	157	(1,122)
Net unrealized gains on derivative instruments during the period	49,770	6,820	8,576
Reversal of net unrealized (gains) losses on derivative instruments settled during the period	(19,164)	(10,418)	181
Loss from settlement of cash flow hedge contracts	(22,960)	--	--
Amortization of cash flow hedge contracts to earnings	455	--	--
Deferral of cash flow hedges related to power cost adjustment mechanism	12,905	(3,103)	(16,055)
Other comprehensive income (loss)	21,931	(6,544)	(9,983)
Comprehensive income	$ 168,700	$ 119,648	$ 109,903

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	2005	2004	2003
Operating activities:			
Net income	$ 146,769	$ 126,192	$ 119,886
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	241,634	228,566	220,087
Deferred federal income taxes and tax credits – net	(57,597)	72,446	49,276
Power cost adjustment mechanism	(18,380)	3,605	(3,605)
Gain from sale of securities	--	--	(2,889)
Net unrealized (gain) loss on derivative instruments	472	(526)	106
Other (including conservation amortization)	138	17,201	18,196
Cash collateral received from (returned to) energy suppliers	15,700	6,320	(21,425)
Gas pipeline capacity assignment	55,000	--	--
BPA prepaid transmission	(10,750)	--	--
Increase (decrease) in residential exchange program	(4,941)	1,668	(25,989)
Pension plan funding	--	--	(26,521)
Change in certain current assets and current liabilities:			
Accounts receivable and unbilled revenue	(221,960)	8,264	33,370
Materials and supplies	(4,808)	(37,884)	(12,238)
Fuel and gas inventory	(25,163)	17,512	1,405
Prepayments and other	(776)	38	2,622
Purchased gas receivable / liability	(48,246)	(31,073)	(71,826)
Accounts payable	116,743	23,282	12,863
Taxes payable	30,265	(707)	17,910
Tenaska disallowance reserve	(3,156)	3,156	--
Accrued expenses and other	(2,201)	(2,664)	(4,120)
Net cash provided by operating activities	208,743	435,396	304,298
Investing activities:			
Construction expenditures – excluding equity AFUDC	(568,381)	(393,891)	(269,973)
Energy efficiency expenditures	(24,428)	(24,852)	(18,579)
Restricted cash	586	905	20,106
Cash received from sale of securities	--	--	3,161
Cash received from property sales	24,291	1,315	2,075
Refundable cash received for customer construction projects	9,869	13,424	5,045
Other	6,006	129	1,596
Net cash used by investing activities	(552,057)	(402,970)	(256,569)
Financing activities:			
Decrease in short-term debt – net	41,000	--	(30,340)
Dividends paid	(89,199)	(87,700)	(86,671)
Issuance of bonds and notes	400,000	200,000	304,465
Redemption of preferred stock	--	--	(60,000)
Redemption of mandatorily redeemable preferred stock	--	--	(41,273)
Redemption of trust preferred stock	(42,500)	--	(19,750)
Redemption of bonds and notes	(231,000)	(157,658)	(356,860)
Settlement of interest rate derivative	(35,323)	--	--
Investment from Puget Energy	314,687	5,016	106,124
Issuance costs and other	(10,597)	6,093	(10,121)
Net cash provided (used) by financing activities	347,068	(34,249)	(194,426)
Increase (decrease) in cash from net income	3,754	(1,823)	(146,697)
Cash at beginning of year	12,955	14,778	161,475
Cash at end of year	$ 16,709	$ 12,955	$ 14,778
Supplemental Cash Flow Information:			
Cash payments for:			
Interest (net of capitalized interest)	$ 172,986	$ 175,772	$ 187,256
Income taxes (net of refunds)	126,591	(1,042)	(1,456)

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 (PUHCA) of 1935. The Energy Policy Act of 2005 repealed the PUHCA of 1935 effective February 8, 2006. 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. The financial position and results of operations for InfrastruX have been presented as discontinued operations. Puget Energy previously had two reportable segments which included regulated operations (PSE) and utility construction services (InfrastruX). With the treatment of InfrastruX as discontinued operations, Puget Energy now has only one reportable segment. 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. 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 and major maintenance 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, are 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 historical 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, including assets to be disposed of, are impaired and how losses, if any, should be recognized. The Company believes that the present value of the estimated future cash inflows from the use and eventual disposition of long-lived assets is sufficient to recover their carrying values.

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 2005, 2004 and 2003; depreciable gas utility plant was 3.4% in both 2005 and 2004 and 3.5% in 2003; and depreciable common utility plant was 4.8% in 2005, 4.6% in 2004 and 4.7% in 2003. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

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 $1.0 million at December 31, 2005 which represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. Restricted cash at December 31, 2004 amounted to $1.6 million of which $1.1 million represented funds held by Puget Western, Inc. and $0.5 million related to funds for payment to conservation trust debt and funds for the Residential and Farm Energy Exchange Benefit Credit program provided to customers.

MATERIAL AND SUPPLIES

Material and supplies consists primarily of materials and supplies used in the operation and maintenance of electric and gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. These items are recorded at lower of cost or market value using the weighted average cost method.

FUEL AND GAS INVENTORY

Fuel and gas inventory is used in the generation of electricity and for future sales to the Company's gas customers. Fuel inventory consists of coal, diesel, and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas held in storage for future sales. These items are recorded at lower of cost or market value 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 were 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 was 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 through March 3, 2005. Effective March 4, 2005 based on the 2004 general rate case, the Company is allowed a return on the net regulatory assets and liabilities of 8.40% for both electric and gas rates. The net regulatory assets and liabilities at December 31, 2005 and 2004 included the following:

(DOLLARS IN MILLIONS)	REMAINING AMORTIZATION PERIOD	2005	2004
PURPA electric energy supply contract buyout costs	3 to 6 years	$ 191.2	$ 211.2
Deferred income taxes	***	129.7	127.3
White River relicensing and other costs	*	66.1	65.3
Investment in Bonneville Exchange Power contract	11 years	40.6	44.1
Environmental remediation	*	34.2	42.4
Deferred AFUDC	30 years	32.0	30.4
Tree watch costs	9.3 years	24.2	28.3
Storm damage costs – electric	2.4 years	15.0	21.1
Purchased Gas Adjustment (PGA) receivable	*	67.3	19.1
Colstrip common property	18 years	13.2	13.9
Hopkins Ridge prepaid transmission upgrade	*	10.8	--
PGA deferral of unrealized losses on derivative instruments	***	--	12.1
Various other regulatory assets	1 to 26 years	31.6	30.1
Power Cost Adjustment (PCA) mechanism	*	18.4	--
Cost of removal	**	(125.3)	(132.4)
PCA deferral of unrealized gain on derivative instruments	***	(11.1)	(30.8)
Gas Supply contract settlement	2.5 year	(9.5)	(10.1)
Deferred gains on property sales	3 years	(11.4)	(4.5)
PGA deferral of unrealized gains on derivative instruments	***	(25.7)	--
Tenaska disallowance reserve		--	(3.2)
Deferred credit gas pipeline capacity	11.8 years	(55.0)	--
Various other regulatory liabilities	1 to 22 years	(3.9)	(4.7)
Net regulatory assets and liabilities		$ 432.4	$ 459.6

* *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 meets 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 $125.3 million and $132.4 million in 2005 and 2004, 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 8.40% beginning March 4, 2005 and 8.76% for the period September 1, 2002 through March 3, 2005. The allowed AFUDC rate on electric utility plant was 8.40% beginning March 4, 2005 and 8.76% for the period July 1, 2002 through March 3, 2005. 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 $2.8 million for 2005, $1.4 million for 2004 and $1.6 million for 2003. The deferred asset is being amortized over the average useful life of the Company's non-project utility plant.

California Reserve

PSE operates within the western wholesale market and has made sales into the California energy market. 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 receivable balance of $21.3 million at December 31, 2005 is collectible from the CAISO.

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 or upon the sale of assets.

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.

Puget Energy's allowance for doubtful accounts for 2005 and 2004 was $3.1 million and $2.7 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 those which are storm related. The Washington Commission has approved the deferral of certain uninsured storm damage costs that exceed $5.0 million in 2005 and exceed $7.0 million in 2006 and 2007 for collection in future rates.

Federal Income Taxes

Puget Energy and its subsidiaries file consolidated federal income tax returns. Income taxes are allocated to the subsidiaries on the basis of separate company computations of taxable income or loss. The Company provides for deferred taxes on certain assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes, as required by SFAS No. 109, "Accounting for Income Taxes." The Company began earning Production Tax Credits when its Hopkins Ridge wind generating facility was completed on November 27, 2005. The amount of the tax credit is currently 1.9 cents per kilowatt-hour for wind generation.

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 is 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 an electric 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. On October 20, 2005, the Washington Commission approved an amendment to the PCA mechanism changing the PCA period to a calendar year beginning January 1, 2007. The Washington Commission also made provision to reduce the graduated scale to half the annual excess power costs for the period July 1, 2006 through December 31, 2006 without a cap on excess power costs. 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	July 2006 – December 2006 Power Cost Variability[1]	Customers' Share	Company's Share[2]
+/- $20 million	+/- $10 million	0%	100%
+/- $20 million - $40 million	+/- $10 - $20 million	50%	50%
+/- $40 million - $120 million	+/- $20 - $60 million	90%	10%
+/- $120+ million	+/- $60 million	95%	5%

[1] *In October 2005, the Washington Commission in its Power Cost Only Rate Case order made a provision to reduce the power cost variability amounts to half the annual power cost variability for the period July 1, 2006 through December 31, 2006.*

[2] *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 without a cap.*

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, 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.

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 for the purpose of serving retail load. 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 on 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 in earnings. 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 in offsetting cash flows attributable to 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 mechanism through June 30, 2006.

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. The Company adopted SFAS No. 123R on January 1, 2006 and does not expect the expense for stock-based compensation computed in accordance with SFAS No. 123R to be materially different than the expense computed under SFAS No. 123. 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	2005	2004	2003
Net income, as reported	$ 155,726	$ 55,022	$ 116,197
Add: Total stock-based employee compensation expense included in net income, net of tax	1,652	2,457	4,114
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(2,195)	(2,603)	(2,433)
Pro forma net income	$ 155,183	$ 54,876	$ 117,878
Earnings per common share:			
Basic as reported	$ 1.52	$ 0.55	$ 1.23
Diluted as reported	$ 1.51	$ 0.55	$ 1.22
Basic pro forma	$ 1.51	$ 0.55	$ 1.24
Diluted pro forma	$ 1.51	$ 0.55	$ 1.24

DEBT RELATED COSTS

Debt premiums, discounts, expenses and amounts received or incurred to settle interest rate hedges 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.

INTANGIBLES (PUGET ENERGY ONLY)

Puget Energy performs an annual impairment review under SFAS No. 142, "Goodwill and Other Intangible Assets," to determine if any impairment exists. 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. In 2004, InfrastruX recorded a $91.2 million ($76.6 million after tax and minority interest) impairment charge related to goodwill from acquired companies.

EARNINGS PER COMMON SHARE (PUGET ENERGY ONLY)

Basic earnings per common share has been computed based on weighted average common shares outstanding of 102,570,000, 99,470,000 and 94,750,000 for 2005, 2004 and 2003, respectively. Diluted earnings per common share has been computed based on weighted average common shares outstanding of 103,111,000, 99,911,000 and 95,309,000 for 2005, 2004 and 2003, respectively, which includes the dilutive effect of securities related to employee stock-based compensation plans.

ACCOUNTS RECEIVABLE SECURITIZATION PROGRAM

On December 20, 2005, PSE entered into a five-year Receivable Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned, bankruptcy-remote subsidiary of PSE, formed for the purpose of purchasing customers' accounts receivable, both billed and unbilled. The accounts receivable are sold at estimated fair value, based on the present value of discounted cash flows taking into account anticipated credit losses, the speed of payments and the discount rate commensurate with the uncertainty involved. The PSE Funding agreement replaces the Rainier securitization facility that was terminated on December 20, 2005. In addition, PSE Funding entered into a Loan and Servicing Agreement with PSE and two banks. The Loan and Servicing Agreement allows PSE Funding to use the receivables as collateral to secure short-term loans, not exceeding the lesser of $200 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers. The PSE Funding receivables securitization facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. PSE Funding had $41.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2005.

Rainier Receivables, Inc. (Rainier Receivables) 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 had an agreement whereby Rainier Receivables would sell, on a revolving basis, up to $150 million of those eligible receivables. The agreement expired December 20, 2005. Rainier Receivables was 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.

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 requires 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 was originally effective for interim reporting periods beginning after June 15, 2005. However, on April 14, 2005, the Securities and Exchange Commission delayed implementation of SFAS No. 123R to annual reporting periods beginning after June 15, 2005, which will be January 1, 2006 for the Company. The Company adopted the fair value provisions of SFAS No. 123 "Accounting for Stock Based Compensation" in January 2003. The Company adopted SFAS No. 123R on January 1, 2006.

The Company does not expect the expense for stock options computed in accordance with SFAS No. 123R to be materially different than the expense computed under SFAS No. 123. SFAS No. 123R requires that the total impact of adopting the standard be accounted for as a cumulative effect of an accounting change net of tax.

On May 19, 2004, FASB issued FASB Staff Position No. 106-2 "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare

Prescription Drug Improvement 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 new Medicare regulations issued in May 2005, the Company determined that it provides benefits at a higher level than provided under Medicare Part D, and therefore would qualify for federal tax subsidies. As a result, the Company reduced its accumulated post retirement benefit obligation by $4.1 million in the second quarter 2005 and reduced its estimated accrued expense recorded for the 2005 plan year by $0.6 million.

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, 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 with no impact on net income.

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 power purchase 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 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 power purchase 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 power purchase 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 2005, 2004 and 2003 for these three entities was $267.0 million, $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 March 2005, FASB issued FIN 47, which finalized a proposed interpretation of SFAS No. 143 titled "Accounting for Conditional Asset Retirement Obligations." The 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. FIN 47 was effective for the year ended December 15, 2005, and was required to be accounted for as a cumulative effect of an accounting change. The Company adopted FIN 47 in the fourth quarter 2005, which resulted in the recognition of a cumulative effect for the asset retirement obligations amounting to $0.1 million after tax.

NOTE 3. *Discontinued Operations*

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. Puget Energy intends to monetize its interest in InfrastruX through a sale. Puget Energy believes the planned disposal of InfrastruX meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements in 2005. Puget Energy is actively marketing InfrastruX and retained an investment banking firm to assist in the disposal of InfrastruX. To date, Puget Energy has not entered into a definitive agreement that would result in the sale of its investment in InfrastruX.

For 2005, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $9.5 million compared to a loss of $70.4 million and income of $1.8 million (net of taxes and minority interest) for 2004 and 2003, respectively. Included in the income for discontinued operations is a charge of $12.4 million after-tax for 2005 to adjust Puget Energy's carrying value of InfrastruX to the estimated fair value and for transaction costs. In accordance with SFAS No. 144, Puget Energy discontinued depreciation and amortization of InfrastruX's assets effective February 8, 2005. The following table summarizes Puget Energy's income from discontinued operations for 2005, 2004 and 2003:

(DOLLARS IN THOUSANDS)	2005	2004	2003
Income from operations reported by InfrastruX	$ 11,418	$ 6,765	$ 1,943
Goodwill impairment	(13,874)	(91,196)	--
Tax provision on goodwill impairment	--	24,961	--
Net income (loss) at InfrastruX	(2,456)	(59,470)	1,943
Goodwill impairment not recognized at Puget Energy	13,874	--	--
InfrastruX depreciation and amortization not recorded by Puget Energy, net of tax	10,826	--	--
Puget Energy tax benefit (valuation allowance) from goodwill impairment	1,912	(17,987)	--
Carrying value adjustment to estimated fair value and transaction costs	(12,464)	--	--
Minority interest in income from discontinued operations	(2,178)	7,069	(177)
Income (loss) from discontinued operations	$ 9,514	$ (70,388)	$ 1,766

InfrastruX's bank and vendor debt under its credit agreements totaled $130.3 million at December 31, 2005 compared to $159.4 million at December 31, 2004. In May 2004, InfrastruX signed a three-year agreement with a group of banks to provide up to $150 million in financing, with Puget Energy as guarantor. Certain InfrastruX subsidiaries also have borrowing capacities for working capital purposes of which Puget Energy is not the guarantor. Of the $150 million bank facility available to InfrastruX, $112 million was outstanding at December 31, 2005 and $131 million was outstanding at December 31, 2004. In determining the fair value of its InfrastruX investment, Puget Energy has determined proceeds of a sale will first be used to extinguish all outstanding InfrastruX debt.

In accordance with SFAS No. 144, Puget Energy has adjusted the carrying value of its investment in InfrastruX to the estimate of fair value, less selling costs, at December 31, 2005. This estimate could change as a result of InfrastruX's financial performance and market conditions in the utility constructions services sector. After reflecting a carrying value reduction and related transaction costs of $12.4 million in 2005, Puget Energy's equity investment in InfrastruX was $43.5 million at December 31, 2005 compared to $33.8 million in 2004. Puget Energy's carrying value under SFAS No. 144 as compared to fair value of its InfrastruX investment was not impacted by the non-cash goodwill impairment recorded by InfrastruX under SFAS No. 142 due to discontinued operations of InfrastruX. As a result, Puget Energy did not record the effects of the goodwill impairment under SFAS No. 142. It is not anticipated that any funding will be needed from Puget Energy to maintain operations at InfrastruX or to complete the sale transaction.

The following amounts related to InfrastruX have been segregated from continuing operations and reflected as discontinued operations:

TWELVE MONTHS ENDED (DOLLARS IN THOUSANDS)	2005	2004	2003
Revenues	$ 393,294	$ 369,936	$ 341,787
Goodwill impairment charge	(13,874)	(91,196)	--
Operating expenses (including interest expense)	(370,068)	(357,990)	(338,250)
Pre-tax income	9,352	(79,250)	3,537
Income tax expense	(11,534)	1,793	(1,594)
Goodwill impairment not recognized by Puget Energy	13,874	--	--
Minority interest in income of discontinued operations	(2,178)	7,069	(177)
Income (loss) from discontinued operations	$ 9,514	$ (70,388)	$ 1,766

In accordance with SFAS No. 144, InfrastruX discontinued depreciation and amortization of its assets effective February 8, 2005. This discontinuation of depreciation and amortization resulted in $16.8 million ($10.8 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for 2005.

InfrastruX's summarized balance sheets, including intercompany balances eliminated in consolidation, are as follows:

(DOLLARS IN THOUSANDS)	DECEMBER 31, 2005	DECEMBER 31, 2004
Assets:		
Cash	$ 6,187	$ 6,817
Accounts receivable	78,842	78,646
Other current assets	22,405	25,459
Total current assets	107,434	110,922
Goodwill	43,886	43,503
Intangibles	14,443	16,680
Non-utility property and other	108,784	100,115
Total long-term assets	167,113	160,298
Total assets	$ 274,547	$ 271,220
Liabilities:		
Accounts payable	$ 9,178	$ 9,773
Short-term debt	3,809	8,297
Current maturities of long-term debt	6,477	7,933
Other current liabilities	36,327	25,889
Total current liabilities	55,791	51,892
Deferred income taxes	24,645	25,828
Long-term debt	120,013	143,172
Other deferred credits	16,986	14,710
Total long-term liabilities	161,644	183,710
Total liabilities	$ 217,435	$ 235,602

GOODWILL AND INTANGIBLES.

Puget Energy allocates goodwill to reporting units based on the excess purchase price over tangible and identifiable intangible assets. SFAS No. 142, "Goodwill and Other Intangible Assets," 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 2005, InfrastruX, as part of its annual impairment review of goodwill, recorded a non-cash goodwill impairment charge of $13.8 million. Puget Energy reviews its investment in InfrastruX under SFAS No. 144 "Accounting for the impairment or Disposal of Long-Lived Assets" and determined that its carrying value of InfrastruX should not recognize the goodwill impairment charge recorded at InfrastruX. Puget Energy, however, adjusted its carrying value and transaction costs by $12.4 million as a result of InfrastruX discontinuing its depreciation and amortization once it was presented on a discontinued operations basis.

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. During 2005, patents pending amounting to $0.1 million were written off and no intangible assets were added. 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, 2005 (Dollars in Thousands)	Gross Intangibles	Accumulated Amortization	Net Intangibles
Covenant not to compete	$ 4,178	$ 3,571	$ 607
Developed technology	14,190	3,873	10,317
Contractual customer relationships	4,702	1,903	2,799
Patents	897	177	720
Total	$ 23,967	$ 9,524	$ 14,443

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

Puget Energy has provided a valuation allowance against its deferred tax asset related to the excess of its outside tax basis over the financial reporting basis of the Company's investment in InfrastruX. It is more likely than not that the deferred tax asset will not be realized. The valuation allowance was $16.6 million and $18.0 million at December 31, 2005 and 2004, respectively.

NOTE 4. *Utility and Non-Utility Plant*

Utility Plant (Dollars In Thousands) At December 31	Estimated Useful Life (Years)	2005	2004
Electric, gas and common utility plant classified by prescribed accounts at original cost:			
Distribution plant	10-60	$ 4,469,818	$ 4,219,720
Production plant	40-100	1,326,383	1,150,781
Transmission plant	30-95	440,679	426,543
General plant	10-35	363,382	346,472
Construction work in progress	NA	216,513	129,966
Intangible plant (including capitalized software)	3-29	288,509	283,179
Plant acquisition adjustment	21	76,623	76,623
Underground storage	50-80	23,880	23,089
Liquefied natural gas storage	14-50	12,339	12,345
Plant held for future use	--	9,153	7,296
Other	27-34	6,139	5,313
Less: accumulated provision for depreciation		(2,602,500)	(2,452,969)
Net utility plant		$ 4,630,918	$ 4,228,358

Non-Utility Plant (Dollars In Thousands) At December 31	Estimated Useful Life (Years)	2005	2004
Non-utility plant	3-20	$ 3,113	$ 2,791
Less: accumulated provision for depreciation		445	445
Net non-utility plant		$ 2,668	$ 2,346

Non-utility plant is composed primarily of land and land rights that are not included in rate-based property. Non-utility plant and accumulated depreciation are included in "other" under "other property and investments" in the Puget Energy and PSE balance sheets.

The Company identified various asset retirement obligations under SFAS No. 143, "Accounting for Asset Retirement Obligations," upon initial adoption, and in 2005 identified additional asset retirement obligations to replace bare steel natural gas pipe and for the future removal of wind turbine generators. In March 2005, FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations," (ARO) which provides guidance on when an asset retirement obligation that is conditional on a future event should be recognized. The Company adopted FIN 47 in the fourth quarter 2005 which resulted in the recognition of additional asset retirement obligations. FIN 47 also requires that if an entity has any asset retirement obligations for which no amount has been recognized, the existence of the ARO must be disclosed and the reasons why the liability has not been recognized.

Prior to the adoption of FIN 47, the Company recognized an obligation to: (1) dismantle two leased electric generation turbine units and deliver the turbines to the nearest railhead at the termination of the lease in 2009; (2) remove certain structures as a result of re-negotiations with the Department of Natural Resources of a now expired lease; (3) replace or line all cast iron pipes in its service territory by 2007 as a result of a 1992 Washington Commission order; (4) restore ash holding ponds at a jointly-owned coal-fired electric generating facility in Montana; (5) replace all unprotected bare steel gas pipe in its service territory by 2015 as a result of a January 31, 2005 Washington Commission order; and (6) to remove wind turbine generators and related equipment, improvements and fixtures at the termination of the related leases. The adoption of FIN 47 in the fourth quarter 2005 resulted in recognition of additional asset retirement obligations to: (1) dispose of treated wood poles; (2) dispose oil containing PCBs and the related equipment that held the oil; (3) remove asbestos in facilities that have been identified for remodeling or demolishing; and (4) to disconnect abandoned pipelines, purge of gas and cut and cap supplies of gas.

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

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2005	2004
Asset retirement obligation at beginning of year	$ 3,516	$ 3,421
Liability recognized in transition	22,084	--
New asset retirement obligation liability recognized in the period	2,841	--
Liability settled in the period	(382)	--
Accretion expense	215	95
Asset retirement obligation at December 31	$ 28,274	$ 3,516

The Company has identified the following obligations which were not recognized at December 31, 2005: (1) a legal obligation under the Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sale. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated currently; (2) an obligation under state of Washington law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated currently; (3) an obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely, therefore: the liability cannot be reasonably estimated currently; (4) a legal obligation under the state of Washington environmental laws to remove and properly dispose of underground storage fuel tanks. The disposal costs related to underground storage tanks could not be measured since the retirement date is indeterminable; therefore the liability cannot be reasonably estimated currently; and (5) a potential legal obligation, arising (if at all) upon the expiration of an existing FERC hydropower license, were FERC to then order project decommissioning, although PSE contends that FERC does not have such authority. Regardless, given the value of ongoing generation, flood control, and other benefits provided by these projects, PSE believes that the potential for decommissioning is both remote and cannot be reasonably estimated.

The pro forma asset retirement obligation liability balances as if SFAS No. 143, as interpreted by FIN 47, had been adopted on December 31, 2002 (rather than December 31, 2005) are as follows:

(DOLLARS IN THOUSANDS)	
Pro forma amounts of liability for asset retirement obligation at January 1, 2003	$ 25,208
Pro forma amounts of liability for asset retirement obligation at December 31, 2003	25,281
Pro forma amounts of liability for asset retirement obligation at December 31, 2004	25,297

The pro forma income statement effect as if SFAS No. 143, as interpreted by FIN 47, had been adopted on December 31, 2002 (rather than December 31, 2005) is as follows:

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	2005	2004	2003
Net income, as reported	$ 155,726	$ 55,022	$ 116,197
Add: SFAS No. 143 transition adjustment, net of tax	--	--	169
Add: FIN 47 transition adjustment, net of tax	71	--	--
Less: Pro forma accretion expense, net of tax	--	--	--
Pro forma net income	$ 155,797	$ 55,022	$ 116,366
Earnings per share:			
Basic as reported	$ 1.52	$ 0.55	$ 1.23
Diluted as reported	$ 1.51	$ 0.55	$ 1.22
Basic pro forma	$ 1.52	$ 0.55	$ 1.23
Diluted pro forma	$ 1.51	$ 0.55	$ 1.22

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 $331.9 million at December 31, 2005. For the years 2005, 2004 and 2003, the aggregate dividends declared per share were $1.00, $1.00 and $1.00, respectively.

NOTE 7. *Redeemable Securities*

PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

	Preferred Stock Subject to Mandatory Redemption $100 Par Value		
	4.70% Series	4.84% Series	7.75% Series
Shares outstanding December 31, 2002	4,311	14,808	412,500
Acquired for sinking fund:			
2003	--	--	(75,000)
2004	--	--	--
2005	--	--	--
Called for redemption or reacquired and canceled:			
2003	--	(225)	(337,500)
2004	--	--	--
2005	--	--	--
Shares outstanding December 31, 2005	4,311	14,583	--

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

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. At December 31, 2005, there were 31,689 shares of the 4.70% Series and 15,192 shares of the 4.84% Series 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. On May 18, 2005, PSE tendered an offer to repurchase all of PSE's 8.231% Capital Trust Preferred Securities (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheets). As a result of the tender offer, $42.5 million of the Capital Trust Preferred Securities were redeemed on June 2, 2005 at a 4% premium which totaled approximately $4.6 million. 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	2005	2004	SERIES	DUE	2005	2004
6.92%	2005	$ --	$ 11,000	7.12%	2010	$ 7,000	$ 7,000
6.93%	2005	--	20,000	7.96%	2010	225,000	225,000
Variable	2006	--	200,000	7.69%	2011	260,000	260,000
6.58%	2006	10,000	10,000	6.83%	2013	3,000	3,000
8.06%	2006	46,000	46,000	6.90%	2013	10,000	10,000
8.14%	2006	25,000	25,000	5.197%	2015	150,000	--
7.02%	2007	20,000	20,000	7.35%	2015	10,000	10,000
7.04%	2007	5,000	5,000	7.36%	2015	2,000	2,000
7.75%	2007	100,000	100,000	6.74%	2018	200,000	200,000
3.363%	2008	150,000	150,000	9.57%	2020	25,000	25,000
6.51%	2008	1,000	1,000	7.15%	2025	15,000	15,000
6.53%	2008	3,500	3,500	7.20%	2025	2,000	2,000
7.61%	2008	25,000	25,000	7.02%	2027	300,000	300,000
6.46%	2009	150,000	150,000	7.00%	2029	100,000	100,000
6.61%	2009	3,000	3,000	5.483%	2035	250,000	--
6.62%	2009	5,000	5,000	Total		$2,102,500	$1,933,500

In April 2005, 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 $850.0 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 May 2005, PSE completed the issuance of $250.0 million of senior notes secured by first mortgage bonds, at a rate of 5.483%. The net proceeds from the issuance of the senior notes of approximately $247.6 million were used to redeem $200.0 million of variable rate senior notes, which were redeemed at par in May 2005, and to repay a portion of PSE's short-term debt. In October 2005, PSE completed the issuance of $150.0 million of senior notes secured by first mortgage bonds, at a rate of 5.197%, due October 1, 2015. The net proceeds from the issuance of the senior notes of approximately $149.0 million were used to repay a portion of PSE's short-term debt. The capacity available under the shelf-registration statement, as of February 21, 2006, was $138.0 million.

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, 2005, the earnings available for interest exceeded the required amount.

POLLUTION CONTROL BONDS

The Company has two series of Pollution Control Bonds outstanding. 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	2005	2004
2003A Series – 5.00%	2031	$ 138,460	$ 138,460
2003B Series – 5.10%	2031	23,400	23,400
Total		$ 161,860	$ 161,860

LONG-TERM REVOLVING CREDIT FACILITY (PUGET ENERGY ONLY)

On September 29, 2005, Puget Energy paid off a $5.0 million outstanding balance under a $5.0 million credit agreement with a bank and closed the credit agreement.

LONG-TERM DEBT MATURITIES

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

PUGET ENERGY AND PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2006	2007	2008	2009	2010	THEREAFTER
Maturities of:						
Long-term debt	$ 81,000	$ 125,000	$ 179,500	$ 158,000	$ 232,000	$ 1,488,860

NOTE 9. *Liquidity Facilities and Other Financing Arrangements*

At December 31, 2005, PSE had borrowing arrangements that included a five-year $500 million unsecured credit agreement with a group of banks and a five-year $200 million receivables securitization program. These arrangements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. The bank credit agreement allows the Company to make floating rate advances at either LIBOR plus a spread or the banks' prime rate and contains "credit sensitive" pricing with various spreads associated with various credit rating levels. The bank credit agreement also allows for issuing standby letters of credit up to the entire amount of the credit agreement. The bank credit agreement expires in April 2010.

On December 20, 2005, PSE entered into a five-year Receivable Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned subsidiary of PSE, replacing the Rainier Receivables securitization facility that was terminated on December 20, 2005. Pursuant to the Receivables Sales Agreement, PSE sells all of its utility customer accounts receivable and unbilled utility revenues to PSE Funding. In addition, PSE Funding entered into a Loan and Servicing Agreement with PSE and two banks. The Loan and Servicing Agreement allows PSE Funding to use the receivables as collateral to secure short-term loans, not exceeding the lesser of $200 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers.

The PSE Funding receivables securitization facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. During 2005, PSE Funding borrowed a cumulative amount of $70.0 million secured by accounts receivable and had $41.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2005. During 2005 and 2004, Rainier Receivables had sold a cumulative amount of $351.9 million and $600.2 million in accounts receivable, respectively. At December 31, 2004, Rainier Receivables had $150.0 million of accounts receivable sold under the program.

In addition, PSE has an uncommitted $20 million unsecured credit agreement with a bank. Under the terms of the credit agreement, PSE pays a varying interest rate on outstanding borrowings based on the terms entered into at the time of the borrowings. At December 31, 2005, there were no amounts outstanding under this credit agreement. 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, 2005 and 2004.

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2005	2004
Committed financing arrangements:		
Puget Energy line of credit [1]	$ --	$ 15,000
PSE line of credit [2]	500,000	350,000
PSE receivables securitization program [3]	200,000	150,000
Uncommitted financing agreement:		
PSE unsecured credit agreement	$ 20,000	$ --

[1] *On September 29, 2005, Puget Energy cancelled the credit agreement.*

[2] *Provides liquidity support for PSE's outstanding commercial paper and letters of credit in the amount of $0.5 million in 2005 and 2004, effectively reducing the available borrowing capacity under these credit lines to $499.5 million and $349.5 million, respectively. There was no commercial paper outstanding at December 31, 2005 and 2004.*

[3] *Provides liquidity support for PSE's outstanding letters of credit and commercial paper. At December 31, 2005, PSE Funding had borrowed $41.0 million, leaving $159.0 million available to borrow under the receivables securitization program. At December 31, 2004, PSE had sold $150.0 million in receivables under the Rainier Receivables securitization program.*

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, 2005 and 2004.

	2005		2004	
(DOLLARS IN MILLIONS)	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Financial assets:				
Cash	$ 16.7	$ 16.7	$ 19.8	$ 19.8
Restricted cash	1.0	1.0	1.6	1.6
Equity securities	2.0	2.0	1.9	1.9
Notes receivable and other	72.9	72.9	71.4	71.4
Energy derivatives	103.5	103.5	21.9	21.9
Financial liabilities:				
Short-term debt	$ 41.0	$ 41.0	$ 8.3	$ 8.3
Preferred stock subject to mandatory redemption	1.9	1.4	1.9	1.9
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237.8	247.5	280.3	290.9
Long-term debt – fixed-rate[1]	2,264.4	2,416.6	2,051.4	2,194.8
Long-term debt – variable-rate[1]	--	--	200.0	199.9
Energy derivatives	9.8	9.8	19.5	19.5

[1] *PSE's carrying value and fair value of fixed-rate long-term debt in 2005 was the same as Puget Energy's debt. 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.*

The carrying amount of equity securities is considered to be a reasonable estimate of fair value due to limited market pricing and based on the market value as reported by the fund manager. 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 and are recorded at fair value. The Company has a policy that financial derivatives are to be used only to mitigate business risk.

NOTE 11. *Leases*

All leases for the company are operating leases. Certain leases contain purchase options and renewal and escalation provisions. Rent expense net of sublease receipts were:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	
2005	$ 17,145
2004	17,618
2003	19,301

Payments received for the subleases of properties were approximately $0.1 million, $0.1 million and $1.4 million for 2005, 2004 and 2003, respectively.

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

(DOLLARS IN THOUSANDS) AT DECEMBER 31	OPERATING
2006	$ 12,676
2007	13,428
2008	13,141
2009	11,430
2010	7,683
Thereafter	36,853
Total minimum lease payments	$ 95,211

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	2006	2007	2008	2009
Lease receipts	$ 3,249	$ 3,153	$ 3,061	$ 2,490

NOTE 12. *Income Taxes*

The details of income taxes are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Charged to operating expense:			
Current:			
Federal	$ 145,342	$ 5,506	$ 21,990
State	1,936	(21)	(1,460)
Deferred - Federal	(58,116)	71,864	50,880
Deferred investment tax credits	(553)	(593)	(635)
Total charged to operations	88,609	76,756	70,775
Charged to miscellaneous income:			
Current	(3,336)	(5,306)	(276)
Deferred	769	2,470	(1,805)
Total charged to miscellaneous income	(2,567)	(2,836)	(2,081)
Cumulative effect of accounting change	(38)	--	(91)
Total income taxes	$ 86,004	$ 73,920	$ 68,603

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Charged to operating expense:			
Current:			
Federal	$ 146,110	$ 5,825	$ 22,154
State	1,936	(21)	(1,460)
Deferred - Federal	(57,864)	71,966	50,880
Deferred investment tax credits	(553)	(593)	(635)
Total charged to operations	89,629	77,177	70,939
Charged to miscellaneous income:			
Current	(3,336)	(5,306)	(276)
Deferred	769	2,470	(1,805)
Total charged to miscellaneous income	(2,567)	(2,836)	(2,081)
Cumulative effect of accounting change	(38)	--	(91)
Total income taxes	$ 87,024	$ 74,341	$ 68,767

The following reconciliation compares pre-tax book income at the federal statutory rate of 35% to the actual income tax expense in the Consolidated Statements of Income:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Income taxes at the statutory rate	$ 81,275	$ 69,766	$ 64,061
Increase (decrease):			
Utility plant depreciation differences	9,534	10,723	9,130
AFUDC excluded from taxable income	(4,536)	(2,270)	(1,809)
Energy efficiency expenditures	31	(134)	8,096
IRS issue resolution	--	--	(6,209)
Other - net	(300)	(4,165)	(4,666)
Total income taxes	$ 86,004	$ 73,920	$ 68,603
Effective tax rate	37.0%	37.1%	37.5%

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Income taxes at the statutory rate	$ 81,827	$ 70,187	$ 66,028
Increase (decrease):			
Utility plant depreciation differences	9,534	10,723	9,130
AFUDC excluded from taxable income	(4,536)	(2,270)	(1,809)
Energy efficiency expenditures	31	(134)	8,096
IRS issue resolution	--	--	(6,209)
Other - net	168	(4,165)	(6,469)
Total income taxes	$ 87,024	$ 74,341	$ 68,767
Effective tax rate	37.2%	37.1%	36.5%

The Company's deferred tax liability at December 31, 2005, 2004 and 2003 is composed of amounts related to the following types of temporary differences:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Utility plant and equipment	$ 733,581	$ 755,758	$ 719,081
Capitalized overhead costs	33,166	72,448	70,834
Other deferred tax liabilities	64,031	24,334	28,024
Subtotal deferred tax liabilities	830,778	852,540	817,939
Contributions in aid of construction	(49,171)	(41,525)	(46,520)
Other deferred tax assets	(31,830)	(17,139)	(30,909)
Subtotal deferred tax assets	(81,001)	(58,664)	(77,429)
Total	$ 749,777	$ 793,876	$ 740,510

The above amounts have been classified in the Consolidated Balance Sheets as follows:

	2005	2004	2003
Current deferred taxes	$ 10,968	$ (1,415)	$ 1,683
Non-current deferred taxes	738,809	795,291	738,827
Total	$ 749,777	$ 793,876	$ 740,510

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2005	2004	2003
Utility plant and equipment	$ 733,581	$ 755,758	$ 719,081
Capitalized overhead costs	33,166	72,448	70,834
Other deferred tax liabilities	64,384	24,435	28,024
Subtotal deferred tax liabilities	831,131	852,641	817,939
Contributions in aid of construction	(49,171)	(41,525)	(46,520)
Other deferred tax assets	(31,830)	(17,139)	(30,909)
Subtotal deferred tax assets	(81,001)	(58,664)	(77,429)
Total	$ 750,130	$ 793,977	$ 740,510

The above amounts have been classified in the Consolidated Balance Sheets as follows:

	2005	2004	2003
Current deferred taxes	$ 10,968	$ (1,415)	$ 1,683
Non-current deferred taxes	739,162	795,392	738,827
Total	$ 750,130	$ 793,977	$ 740,510

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, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. Deferred tax provisions are not recorded in the income statement for certain temporary differences which are not allowed for ratemaking purposes. Because of prior and expected future ratemaking treatment for temporary differences for which flow-through tax accounting has been utilized, PSE has also established a regulatory asset for income taxes recoverable through future rates related to those differences. The balance of this asset was $129.7 million at December 31, 2005 and $127.3 million at December 31, 2004.

Puget Energy has provided a valuation allowance against its deferred tax asset related to the excess of the outside tax basis over the financial reporting basis of the Company's investment in discontinued operations. It is more likely than not that the deferred tax asset will not be realized. The valuation allowance was $16.6 million at December 31, 2005.

On July 12, 2005, Puget Energy received a notice of proposed adjustment (NOPA) from the Internal Revenue Service relating to a deduction in Puget Energy's 2003 tax return. The deduction relates to the receivable balance due from the California Independent System Operator. The NOPA states that the deduction was not valid for the 2003 tax year and would require repayment of approximately $14.5 million in tax. Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction; however, the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings, as it would be recognized as a deferred tax asset. If the Company is unsuccessful, a charge for interest expense could apply.

During 2002, PSE changed its tax accounting method with respect to capitalized internal labor and overheads, which permitted the Company to immediately deduct certain costs that it had previously capitalized. On August 2, 2005, the Internal Revenue Service and the Treasury Department issued Revenue Ruling 2005-53 and related Regulations. The Revenue Ruling and the Regulations will require utility companies, including PSE, to adopt a less advantageous method of accounting and to repay the accumulated tax benefits. Through September 30, 2005, the Company claimed $66.3 million in accumulated tax benefits. PSE accounted for the accumulated tax benefits as temporary differences in determining its deferred income tax balances. Consequently, the repayment of the tax benefits would not impact earnings but does have a cash flow impact of $33.2 million in the fourth quarter 2005 and $33.1 million in 2006. There is some uncertainty in the new guidance. PSE believes that the new Regulations require the Company to repay the accumulated tax benefits over the 2005 and 2006 tax years and that the tax deductions claimed on the Company's tax returns were appropriate based on the applicable statutes, Regulations, and case law in effect at the time. However, there is no assurance that PSE's position will prevail. If the Company is unsuccessful, a charge for interest expense could apply.

On October 19, 2005, PSE filed an accounting petition with the Washington Commission to defer the capital costs associated with repayment of the deferred tax. The Commission had reduced PSE's rate base by $72 million in its order of February 18, 2005. The accounting petition was approved by the Commission on October 26, 2005, for deferral of additional capital costs beginning November 1, 2005 using PSE's allowed net of tax rate of return. PSE requested recovery of this deferral commencing January 2007 in its February 2006 general rate case filing.

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. Puget Energy also 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)	2005	2004	2005	2004
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 438,635	$ 398,961	$ 31,094	$ 30,300
Service cost	11,549	10,249	305	283
Interest cost	23,855	24,016	1,409	1,736
Amendment[1]	--	--	359	--
Actuarial (gain) loss	3,236	37,766	(4,796)	825
Benefits paid	(22,756)	(32,357)	(2,120)	(2,050)
Benefit obligation at end of year	$ 454,519	$ 438,635	$ 26,251	$ 31,094

1 *The Company had an amendment related to changes in eligibility criteria.*

Change in plan assets:				
Fair value of plan assets at beginning of year	$ 458,980	$ 428,586	$ 15,959	$ 15,431
Actual return on plan assets	43,119	51,395	696	1,184
Employer contribution	2,101	11,356	1,133	1,394
Benefits paid	(22,756)	(32,357)	(2,120)	(2,050)
Fair value of plan assets at end of year	$ 481,444	$ 458,980	$ 15,668	$ 15,959
Funded status	$ 26,925	$ 20,345	$ (10,583)	$ (15,135)
Unrecognized actuarial (gain) loss	68,145	73,454	(7,047)	(3,045)
Unrecognized prior service cost	8,793	11,660	3,396	3,503
Unrecognized net initial (asset) obligation	--	(163)	2,947	3,365
Net amount recognized	$ 103,863	$ 105,296	$ (11,287)	$ (11,312)
Amounts recognized on statement of financial position consist of:				
Prepaid benefit cost	$ 123,318	$ 120,748	$ --	$ --
Accrued benefit liability	(32,430)	(31,014)	(11,662)	(11,312)
Intangible asset	5,689	7,351	375	--
Accumulated other comprehensive income	7,286	8,211	--	--
Net amount recognized	$ 103,863	$ 105,296	$ (11,287)	$ (11,312)

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 $1.9 million, $1.5 million and none, respectively, as of December 31, 2005. For the qualified pension plan, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $454.5 million, $427.4 million and $481.4 million, respectively, as of December 31, 2005.

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 $1.1 million, $0.8 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 $438.6 million, $411.0 million and $459.0 million, respectively, as of December 31, 2004.

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	2005	2004	2003	2005	2004	2003
Discount rate	5.60%	5.60%	6.25%	5.60%	5.60%	6.25%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	11.00%	12.00%	9.00%

	Pension Benefits			Other Benefits		
Benefit Cost Assumptions	2005	2004	2003	2005	2004	2003
Discount rate	5.60%	6.25%	6.75%	5.60%	6.25%	6.75%
Return on plan assets	8.25%	8.25%	8.25%	4.3-8%	4.3-8.25%	6-7.00%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	12.00%	9.00%	10.00%

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and 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.

The discount rate was determined by using market interest rate data and weighted average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

	Pension Benefits			Other Benefits		
(Dollars in Thousands)	2005	2004	2003	2005	2004	2003
Components of net periodic benefit cost:						
Service cost	$ 11,549	$10,249	$ 8,182	$ 305	$ 283	$ 278
Interest cost	23,855	24,016	24,358	1,409	1,736	1,875
Expected return on plan assets	(37,928)	(39,106)	(38,880)	(878)	(858)	(934)
Amortization of prior service cost	2,867	3,033	3,100	466	465	429
Recognized net actuarial (gain) loss	3,354	1,221	(2,602)	(612)	(332)	(427)
Amortization of transition (asset) obligation	(163)	(1,104)	(1,104)	418	418	418
Special recognition of prior service costs	--	--	190	--	--	--
Net pension benefit cost (income)	$ 3,534	$ (1,691)	$ (6,756)	$ 1,108	$ 1,712	$ 1,639

The aggregate expected contributions by the Company to fund the pension and other benefit plans for the year ended December 31, 2006 are $2.1 million and $1.0 million, respectively. The full amount of the pension funding for 2006 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:

	2005		2004	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Short-term investments and cash	2.4%	1.9%	2.4%	5.1%
Equity securities	62.3%	--	67.8%	--
Fixed income securities	15.3%	17.3%	18.2%	20.0%
Mutual funds (equity and fixed income)	20.0%	80.8%	11.6%	74.9%

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)	2006	2007	2008	2009	2010	2011-2015
Total benefits	$30,505	$33,478	$31,998	$33,422	$35,152	$188,213

The assumed medical inflation rate used to determine benefit obligations is 11.0% in 2006 grading down to 6.0% in 2011. A 1% change in the assumed medical inflation rate would have the following effects:

	2005		2004	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 437	$ (378)	$ 552	$ (477)
Effect on service and interest cost components	30	(27)	31	(28)

The Company has a Retirement Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. 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:

	Allocation		
Asset Class	Minimum	Target	Maximum
Short-term investments and cash	--	--	5%
Equity securities	40%	70%	95%
Fixed-income securities	15%	30%	55%
Real estate	--	--	10%

On May 19, 2004, FASB issued FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare Prescription Drug Improvement 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 new Medicare regulations issued in May 2005, the Company determined that it provides benefits at a higher level than provided under Medicare Part D, and therefore would qualify for federal tax subsidies. As a result, the Company reduced its accumulated post retirement benefit obligation by $4.1 million in 2005 and reduced its estimated accrued expense recorded for the 2005 plan year by $0.6 million.

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.

The Company's contributions to the Employee Investment Plans were $6.9 million, $6.3 million and $6.1 million for the years 2005, 2004 and 2003, 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 $2.5 million, $3.8 million and $6.3 million in 2005, 2004 and 2003, respectively. In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment," a revision of SFAS No. 123. Puget Energy will adopt SFAS No. 123R in the first quarter of 2006, as required by the statement. Stock compensation grants outstanding prior to January 1, 2006 will be accounted for under SFAS No. 123 until the grants outstanding vest. The adoption of SFAS No. 123R is not expected to result in a material change to recorded compensation expense.

The Company's Long-Term Incentive Plan (LTI Plan), established in 1995, encompasses many of the awards granted to employees. The plan was amended and restated in 2005, and approved by shareholders. The LTI Plan applies to officers and key employees of the Company and awards granted under this plan include stock awards, performance awards or other stock-based awards as defined by the plan. Any shares awarded are either purchased on the open market or are a new issuance. For plan participants meeting the Company's stock ownership guidelines, up to 50% of the share award may be paid in cash. The maximum number of shares that may be purchased for the LTI Plan is 4,200,000.

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 2005 and four years for grants made prior to 2004 with the final number of shares awarded, and total expense recorded, depending on Puget Energy's performance as compared to other companies and service quality indices for customer service. Compensation expense related to performance share grants was $1.0 million, $2.5 million and $5.1 million for 2005, 2004 and 2003, respectively. The fair value per share of the performance awards granted for the 2005, 2004, 2003 and 2002 cycles was $21.19, $19.70, $16.93 and $21.53, respectively. There were a total of 251,680 performance awards granted for the 2005 cycle of which the Company has estimated a forfeiture rate of 11.8%, or 29,689, awards based on historical forfeitures. In 2004 and 2003 there were 272,307 and 325,896 awards granted, respectively, of which 20,753 and 76,441, respectively, have been forfeited to date. As of December 31, 2005, there are four active grant cycles for a total of 907,983 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 Chairman, 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 the options would become fully vested upon a change of control of the Company or an employment termination without cause. The options expire 10 years from the grant date. All 300,000 options remained outstanding at December 31, 2005, with 202,500 options exercisable. At December 31, 2004 and 2003, 135,000 options and 67,500 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. Beginning January 1, 2006, these options will be expensed under SFAS No. 123R.

RESTRICTED STOCK AND RESTRICTED STOCK UNITS

In 2005, 2004, 2003 and 2002 the Company granted 50,000 shares, 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 or as a new issuance. 40,000 shares under the 2005 grant vest in one installment on the date of the 2008 Annual Shareholders' Meeting based upon performance criteria and the remaining 10,000 shares vest equally over three years. The 2004 grant vests 8,000 shares in three years and the remaining 32,000 shares in four 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 $0.7 million in 2005, $0.5 million in 2004, and $0.6 million in 2003. 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 2005, 2004, 2003 and 2002 was $21.86, $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 and the remaining 8,000 shares in four 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 2005 and 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 chairman, 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 2005, 2004 and 2003, the Company awarded 6,063, 6,469 and 4,319 shares, respectively, which vest over a period from January 1, 2002 to May 2008 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 2005, 2004 and in 2003. The weighted average grant date fair value for the retirement equivalent stock was $24.70, $23.77 and $22.05 for 2005, 2004 and 2003, respectively.

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 through May 2007. In 2005, 2004 and 2003, 58,132, 52,716 and 38,940 shares were issued for the ESPP, respectively. At December 31, 2005, 148,814 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 2005, 2004 and 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 2005, 2004 and 2003 was $4.24, $3.74 and $4.25, 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. The plan was amended and restated in 2005 and approved by shareholders in 2005. Under the plan, which has a term through December 31, 2015, 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 $0.4 million for each of 2005, 2004 and 2003. The Company issues new shares or purchases stock for this plan on the open market up to a maximum of 350,000 shares. As of December 31, 2005, 25,221 shares had been issued or purchased for the director stock plan and 77,741 deferred, for a total of 102,962 shares. As of December 31, 2004 and 2003 the number of shares that had been purchased for the director stock plan was 15,230 and 9,902, respectively, and the number that had been deferred was 64,838 and 48,219, respectively, for a total of 80,068 and 58,121 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 2005, 2004, 2003 and 2002:

STOCK ISSUANCE CYCLE	2005	2004	2003	2002
Performance awards				
Risk-free interest rate	2.50%	2.59%	2.35%	4.00%
Expected lives – years	3.0	3.0	4.0	4.0
Expected stock volatility	15.10%	22.24%	23.85%	23.71%
Dividend yield	4.18%	4.45%	4.86%	8.85%
Employee Stock Purchase Plan				
Risk-free interest rate	2.68%	1.28%	1.07%	*
Expected lives – years	0.5	0.5	0.5	*
Expected stock volatility	13.98%	9.89%	19.47%	*
Dividend yield	4.17%	4.42%	4.39%	*

** Not applicable to comparative financial statements.*

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 ("NPNS") exception to derivative accounting rules, if they meet certain criteria. NPNS applies if the counterparty is creditworthy and has energy resources within PSE's operating area to allow for physical delivery of the energy, and the transaction is within PSE's forecasted load requirements. Those contracts that do not meet NPNS 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 and Purchased Gas Adjustment (PGA) 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 portfolio 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 portfolio 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.

At December 31, 2005, 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 2005, the Company recorded a decrease in earnings of approximately $0.5 million compared to an increase of $0.5 million for 2004 for derivative transactions. The decrease in 2005 primarily related to the reversal of prior period de-designated gas financial hedges for electric generation.

At December 31, 2005, the Company had a short-term asset of $2.2 million and a short-term liability of $0.8 million, primarily as a result of de-designating gas financials for electric generation that was no longer probable. At December 31, 2005, the Company had a short-term asset of $37.9 million and a long-term asset of $28.5 million related to energy contracts designated as cash flow hedges that represent forward financial purchases of gas supply for electric generation of PSE-owned electric plants in future periods. These contracts were designated as qualifying cash flow hedges and the corresponding unrealized gain of $43.2 million, net of tax, was recorded in other comprehensive income. Of the amount in other comprehensive income, 99% of the unrealized mark-to-market gain (or $6.3 million) for the period January 2006 through April 2006 has been reclassified out of other comprehensive income to a deferred account in accordance with SFAS No. 71 due to the Company expecting to exceed the $40 million cap for the PCA mechanism. When these transactions are realized they will be reflected in the PCA mechanism calculation. The amount of cash flow hedges associated with these energy contracts that will reverse and be settled into the income statement during 2006 is approximately $18.4 million, net of SFAS No. 71 deferrals for the period January 2006 through April 2006. This amount includes the reversal of SFAS No. 71 deferrals. At December 31, 2004, the Company had an unrealized gain recorded in other comprehensive income of $0.8 million (net of tax) related to energy contracts which met the criteria for designation as cash flow hedges under SFAS No. 133, net of SFAS No. 71 deferrals. If it is determined that it is uneconomical to run the plants in the future period, the hedging relationship is ended and the cash flow hedge is de-designated and any unrealized gains and losses are recorded in the income statement. Gains and losses, when these de-designated cash flow hedges are settled, are recognized in energy costs and are included as part of the PCA mechanism. At December 31, 2005, the Company had a short-term asset of $34.7 million and a short-term liability of $9.0 million related to the cash flow hedge of gas contracts to serve natural gas customers. This is related to an increase in natural gas prices partly due to disruptions in global supply, resulting in unrealized gains when gas financial hedges are marked to the higher market prices. 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.

At December 31, 2005, the Company had a net short-term unrealized gain on all derivative contracts of $65.2 million compared to a net short-term unrealized loss of $11.8 million at December 31, 2004, reflecting higher forward market prices for natural gas and electricity.

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. In accordance with SFAS No. 133 guidance, 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, 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 2005 and 2004.

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. 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 NPNS exception under SFAS No. 133.

In the second quarter 2005, the Company settled its two treasury lock contracts originating in August 2004. The purpose of the treasury lock contracts was to hedge exposure to interest rate volatility for a debt offering of $250.0 million that was completed in May 2005. Since treasury interest rates related to the hedged debt decreased from the date of issuance of the treasury lock instruments, PSE paid the counterparties $35.3 million for the change in bond value when the contracts were settled. In addition, the bonds issued associated with the treasury lock instruments had a correspondingly lower interest rate since treasury rates decreased from the date of issuance of the treasury lock instruments. The treasury lock contracts were designated and documented 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. In the second quarter 2005, the settlement loss on these instruments amounted to $23.0 million, after-tax, and was recorded as a loss in other comprehensive income. In accordance with SFAS No. 133, this loss is being amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued at an annual rate of approximately $1.2 million pre-tax. The ending balance in other comprehensive income related to the treasury lock contracts at December 31, 2005 was a loss of $22.5 million after-tax and accumulated amortization.

In the second quarter 2005, the Company entered into two forward starting swap contracts to hedge against interest rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting swap 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 designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decreased related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in bond value. These swap contracts were designated under SFAS No. 133 criteria as cash flow hedges. All financial hedge contracts of this type are reviewed by senior management and presented to the Finance and Budget Committee of the Board of Directors, and are approved prior to execution. At December 31, 2005, the unrealized gain associated with the two swap contracts was $0.1 million after-tax and is included in other comprehensive income. The swap contracts will settle completely in 2006.

NOTE 17. *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 accumulated costs under the PCA mechanism for these excess costs. The disallowance was $4.1 million and $43.4 million in 2005 and 2004, respectively. The order also 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.

In August 2004, PSE filed the PCA 2 period compliance 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 $6.0 million related to the period July 1, 2003 through December 31, 2003.

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.

NOTE 18. *Colstrip Matters*

In May 2003, approximately 50 plaintiffs brought an action against the owners of Colstrip. The lawsuit alleged certain domestic water wells may have been contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond. PSE recorded a $0.7 million reserve in the third quarter 2004 for its 50% ownership of the Colstrip Units 1 & 2 project, based upon a tentative settlement agreement in the third quarter 2004. However, the settlement agreement would not resolve certain other claims by residents within the city limits. Before finalizing the settlement, plaintiffs retained new counsel and the litigation continues and is in the discovery phase. Colstrip has extended city water to certain residents who live near the plant in December 2005. PSE reflected the costs to extend the water supply of $0.4 million against the reserve, reducing it to $0.3 million at December 31, 2005. Colstrip continues to address groundwater contamination from wastewater ponds by conducting certain groundwater investigation and remediation measures for certain residents who live near the plant.

On April 29, 2004, the Minerals Management Service of the United States Department of the Interior (MMS) issued an order to Western Energy Company (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. On April 28, 2005, the appeals division of the MMS issued an order that reduced the amount claimed due to the application of statute of limitations. PSE's share of the alleged additional royalties is approximately $1.7 million, which is equivalent to PSE's 25% ownership interest in Colstrip Units 3 & 4. The state of Montana issued a demand to WECO in May 2005 consistent with the MMS position outlined above on these transportation revenues. The state's position, if correct, would result in an additional $0.2 million claim against PSE. 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. However, if the MMS position prevails, this issue could create ongoing expenses as the conveyor system continues to be used. 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.

In January 2006, EPA issued a draft settlement agreement related to an Administrative Compliance Order (ACO) pursuant to the Clean Air Act received by Colstrip in December 2003 related to Colstrip Units 3 & 4. The ACO alleged violation of the Clean Air Act permit at Colstrip since 1980 and contended that Colstrip was obligated to submit for review and approval by EPA an analysis and proposal for reducing emissions of nitrogen oxide to address visibility concerns if and when the EPA promulgates Best Available Retrofit Technology requirements for nitrogen oxide emissions. Although Colstrip believes that the ACO is unfounded, Colstrip is discussing the proposed settlement agreement with EPA, the Montana DEQ and the Northern Cheyenne Tribe. The draft settlement agreement would resolve any potential liability related to this issue.

NOTE 19. *Taxes Other Than Income Taxes*

(DOLLARS IN THOUSANDS)	2005	2004	2003
Taxes other than income taxes:			
Real estate and personal property	$ 44,472	$ 43,843	$ 44,757
State business	93,893	82,408	75,524
Municipal and occupational	85,154	72,405	64,861
Other	30,841	27,766	25,638
Total taxes other than income taxes	$ 254,360	$ 226,422	$ 210,780
Charged to:			
Operating expense	$ 233,742	$ 208,989	$ 194,857
Other accounts, including construction work in progress	20,618	17,433	15,923
Total taxes other than income taxes	$ 254,360	$ 226,422	$ 210,780

NOTE 20. *Regulatory and Other*

On February 15, 2006, PSE filed an electric general rate case requesting an increase in electric general rates of 9.2% or $148.8 million annually. The Company is proposing an adjustment to the annual PCA sharing bands as follows:

POWER COST VARIABILITY	CUSTOMERS' SHARE	COMPANY'S SHARE
+/- $0 - $25 million	50%	50%
+/- $25 - $120 million	90%	10%
+/- $120 million	95%	5%

In addition to the change in sharing bands for the PCA, the Company is requesting the Washington Commission to approve a new depreciation tracker mechanism that would allow the Company to recover increased depreciation expense associated with new plant investment between rate filings. The electric depreciation tracker is 0.5% or $7.9 million of the rate increase. The resolution of the general rate case may be up to an 11-month process from the time the general rate case is filed.

On February 15, 2006, PSE also filed a gas general rate case requesting an increase in gas general rates of 5.3% or $51.3 million annually. The filing included a request for a decoupling mechanism for the natural gas residential and small commercial customers and a natural gas depreciation tracker of 1.2% or $10.9 million of the rate increase. The gas decoupling mechanism does not have an impact on the current rate increase; however, it is designed to stabilize revenue changes due to load variations between regulatory filings. The resolution of the general rate case may be up to an 11-month process from the time the general rate case is filed.

On January 25, 2006, the Washington Commission approved an accounting order to defer, as a regulatory liability, two payments in the amount of $42 million and $13 million received from Duke Energy Trading and Marketing in December 2005 in return for assuming the gas transportation capacity on Northwest Pipeline and Westcoast Pipeline from Duke Energy Trading and Marketing. The regulatory liability will be amortized to gas costs from January 2006 through October 2017 based upon the approved schedule. These credits are an offset to gas transportation costs that are in excess of PSE's gas transportation capacity needs. The $42 million payment was received to compensate the Company for the Northwest capacity payments that must be made until February 2011 when the capacity will be needed to serve load. The $13 million payment was received to compensate the Company for the difference between the assumed tariff rates and market value of the Westcoast capacity through October 2017. The Company requested an accounting order to defer the payment as a regulatory liability, matching the related capacity payments for rate purposes.

On September 28, 2005, the Washington Commission approved PSE's request for a Purchased Gas Adjustment (PGA) mechanism rate increase filed on August 29, 2005. The approved request will increase rates and revenues by approximately 14.7% or $121.6 million annually. On September 24, 2004, the Washington Commission approved PSE's request for a PGA mechanism rate increase, which increased revenues by approximately 17.6% or $121.7 million, annually. The increases in PGA mechanism rates were 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.

On October 20, 2005, the Washington Commission approved a 3.7% or $55.6 million, annually, PCORC increase to allow PSE to recover higher projected costs of power effective November 1, 2005. Included in the increase is the recovery of capital and operating costs of the newly acquired Hopkins Ridge wind project, completed in November 2005. The Washington Commission also approved an amendment to the Power Cost Adjustment (PCA) mechanism by changing the annual PCA reporting periods to a calendar year period beginning January 1, 2007 with provisions made to reduce the sharing bands in half for the period July 1, 2006 through December 31, 2006. The order also requires PSE to update the power cost baseline rate in the PCA mechanism by filing a tariff change to the power cost rate during May 2006 which would be effective July 1, 2006. Finally, the order required PSE to file a general rate case in February 2006 so that a new power cost baseline rate will be effective on January 1, 2007.

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, 2005, the White River project net book value totaled $66.1 million, which included $45.0 million of net utility plant, $15.7 million of capitalized FERC licensing costs, $3.7 million of costs related to construction work in progress and $1.3 million related to dam operation and safety. PSE sought recovery of the relicensing, other construction work in progress and dam operations and safety costs 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. On February 18, 2005, the Washington Commission agreed to allow PSE to recover the White River net utility plant costs noted above. However, amortization of the FERC licensing and other costs will not begin until all costs and any sales proceeds are known.

In November 2005, Puget Energy sold 15 million shares of common stock to Lehman Brothers Inc. for $312 million before underwriting discount. The net proceeds of approximately $309.8 million were invested in PSE and used to repay short-term debt incurred primarily to fund PSE's construction program.

In September 2004, a natural gas fire destroyed a home and took the life of a PSE customer. PSE tendered the matter to its general liability insurer. The civil litigation outcome of this matter and the final associated costs cannot be predicted at this time. However, the Company has recorded a loss reserve for full amount of the self-insurance retention applicable to this matter..

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 $2.0 million at December 31, 2005, 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 equity method accounting. The adoption of the equity method had no cumulative effect on earnings for the year ended December 31, 2005 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 $0.2 million.

NOTE 21. *Commitments and Contingencies*

For the year ended December 31, 2005, approximately 22.7% of the Company's energy output was obtained at an average cost of approximately $0.0140 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 pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project in proportion to the contractual shares that PSE obtains from that project. In these instances, PSE's 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 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, 2005, 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 12/31/05 [2] (MILLIONS)	COMPANY'S ANNUAL AMOUNT PURCHASABLE (APPROXIMATE) % OF OUTPUT	MEGAWATT CAPACITY	COST [3] (MILLIONS)
Rock Island						
Original units	2012	2029	$ 112.6	50.0	352	$ 36.3
Additional units	2012	2029	325.4	55.0		
Rocky Reach	2011	2006	381.0	38.9	501	26.2
Wells	2018	2012	218.1	29.9	251	9.6
Priest Rapids [4, 5, 6]	TBD[7]	TBD[7]	209.7	7.4	67	3.5
Wanapum [4, 5, 6]	2009	TBD[7]	290.5	10.8	103	4.3
Total			$ 1,537.3		1,274	$ 79.9

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 re-financings, 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: 68.7% at Rock Island; 60.3% at Rocky Reach; and 27.7% at Wells. There are no maturities beyond the contract expiration date for Priest Rapids and Wanapum which assumes a 40-year FERC license extension.*

3 *The components of 2005 costs associated with the interest portion of debt service are: Rock Island, $14.9 million for all units; Rocky Reach, $8.3 million; Wells, $2.3 million; Priest Rapids, $0.6 million; and Wanapum, $1.3 million.*

4 *On December 28, 2001, PSE signed a contract offer for three new contracts related to 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. On May 27, 2005, PSE signed additional amendments to those agreements which provided technical clarifications of certain sections of the agreements and consolidated the terms into two contracts. 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. The new contracts' terms begin in November of 2005 for the Priest Rapids Development and in November of 2009 for the Wanapum Development. 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. The complaint is still pending and is in a mediation process.*

5 *Grant County PUD filed an "Application for New License for the Priest Rapids Project" on October 29, 2003 and the original FERC license expired at the end of October 2005. Grant County PUD continues to operate the Priest Rapids Project under annual license extensions pending issuance of a new FERC license and the new contracts will be concurrent with the new license which will be at least 30 years.*

6 *Unlike PSE's expiring contracts with Grant County PUD, in the new contracts PSE's share of power from the Priest Rapids Development and Wanapum Development declines over time as Grant County PUD's load increases. PSE's share of the Wanapum Development will remain at 10.8% until November 2009 and will be adjusted annually thereafter for the remaining term of the new contracts. PSE's share of the Priest Rapids Development declines to approximately 4.3% in 2006 and will be adjusted annually for the remaining term of the new contract.*

7 *To be determined. (See notes 4-6)*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River, contracts with other utilities and contracts under non-utility generators under the Public Utility Regulatory Policies Act (PURPA). These contracts have varying terms and may include escalation and termination provisions.

(DOLLARS IN MILLIONS)	2006	2007	2008	2009	2010	2011 & THERE-AFTER	TOTAL
Columbia River Projects	$ 83.3	$ 89.7	$ 95.6	$ 98.8	$ 91.5	$ 51.6	$ 510.5
Other utilities	83.2	84.1	86.3	85.7	80.4	258.7	678.4
Non-utility generators	195.2	170.1	197.2	194.1	192.6	282.6	1,231.8
Total	$ 361.7	$ 343.9	$ 379.1	$ 378.6	$ 364.5	$ 592.9	$2,420.7

Total purchased power contracts provided the Company with approximately 9.6 million, 9.4 million and 11.0 million MWh of firm energy at a cost of approximately $419.7 million, $404.7 million and $479.2 million for the years 2005, 2004 and 2003, 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, 2005:

			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%	$ 215	$ 140
Colstrip Units 3 & 4	Coal	25%	472	260

Financing for a participant's ownership share in the projects is provided 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 $14.8 million in 2006. The Company has obligations for gas supply amounting to $11.3 million in 2006 for the Tenaska plant.

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 $8.9 million in 2006, $9.2 million in 2007 and $9.6 million in 2008. 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 2.5 years. The obligations under these contracts are $21.6 million in 2006, $21.9 million in 2007 and $11.1 million in 2008. The Company has obligations for gas supply amounting to $4.9 million in 2006 for the Frederickson 1 facility.

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 $217.0 million in 2006 and $27.1 in 2007.

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 17 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts all of its long term firm gas service, which means that the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation. The Company incurred demand charges in 2005 for firm gas supply, firm transportation service and firm storage and peaking service of $1.5 million, $75.3 million and $5.8 million, respectively. WNG CAP I, a PSE subsidiary, incurred demand charges in 2005 for firm transportation service of $3.2 million, which is included in the total Company demand charges. The Company incurred demand charges in 2005 for firm transportation service for the gas supply for its combustion turbines in the amount of $11.0 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)	2006	2007	2008	2009	2010	2011 & THERE-AFTER	TOTAL
Firm gas supply	$ 1.3	$ 1.0	$ 0.8	$ 0.5	$ 0.5	$ 0.5	$ 4.6
Firm transportation service	88.5	85.8	74.2	62.0	33.6	231.0	575.1
Firm storage service	8.3	8.9	7.7	7.7	7.7	29.1	69.4
Total	$ 98.1	$ 95.7	$ 82.7	$ 70.2	$ 41.8	$260.6	$649.1

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 $22.8 million in 2006, $23.4 million in 2007, $23.9 million in 2008, $24.6 million in 2009, $25.2 million in 2010 and $17.1 million 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 $0.9 million in 2006, $1.0 million in 2007, $5.9 million in 2008, $1.2 million in 2009, $2.3 million in 2010 and $11.5 million in the aggregate thereafter.

In March 2005, in connection with its purchase of the Hopkins Ridge wind power project, PSE entered into an Operations, Maintenance and Warranty Agreement (OM&W Agreement) with Vestas-American Wind Technology, Inc. (Vestas American), pursuant to which Vestas American will operate, maintain, service and remedy any defects or deficiencies in the constructed wind turbine generators (or WTGs) at Hopkins Ridge and their associated equipment on PSE's behalf. Vestas American also provides certain warranties in relation to the availability, production and noise of the Hopkins Ridge project. The OM&W Agreement provides for a five-year term continuing until November 2010. The annual fee is approximately $2.4 million and will escalate on each January 1 during the term by the Consumer Price Index.

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 LIBOR. At December 31, 2005, PSE's outstanding balance under the lease was $54.0 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 $6.8 million guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and nine self-insurer's pension bonds totaling $1.3 million.

ENVIRONMENTAL REMEDIATION

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 is recoverable from insurance companies, from third parties or from customers under a Washington Commission order. At December 31, 2005, the Company had $2.5 million and $31.7 million deferred electric and gas environmental costs, respectively.

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 or implementing, 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. The parties to these various actions presented oral arguments to the U.S. Ninth Circuit Court of Appeals in November 2005. A decision from the Court is anticipated in 2006. It is not clear what impact, if any, review of such rates and contracts and the above described U.S. Ninth Circuit Court of Appeals actions may have on PSE.

Other contingencies, arising out of the normal course of the Company's business, exist at December 31, 2005. 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 22. *Segment Information*

Puget Energy operates in one business segment referred to as the regulated utility segment. The regulated utility segment includes the account receivables securitization program. 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.

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.

Prior to 2005, InfrastruX was a reportable segment of Puget Energy. InfrastruX is now reported as discontinued operations and therefore is not considered a reportable segment. See Note 3 for InfrastruX summarized financial information and discussion of discontinued operations.

2005 (Dollars in Thousands)	Regulated Utility	Other	Reconciling Item	Puget Energy Total
Revenues	$ 2,565,384	$ 7,826	$ --	$ 2,573,210
Depreciation and amortization	241,385	249	--	241,634
Income tax	87,749	860	--	88,609
Operating income	299,541	3,622	--	303,163
Interest charges, net of AFUDC	164,965	224	--	165,189
Net income from continuing operations	142,861	3,422	--	146,283
Total assets[2]	6,267,012	68,392	274,547	6,609,951
Construction expenditures - excluding equity AFUDC	568,381	--	--	568,381

2004 (Dollars in Thousands)	Regulated Utility	Other	Reconciling Item	Puget Energy Total
Revenues	$ 2,192,340	$ 6,537	$ --	$ 2,198,877
Depreciation and amortization	228,310	256	--	228,566
Income tax	75,754	1,002	--	76,756
Operating income	285,258	2,420	--	287,678
Interest charges, net of AFUDC	166,411	219	--	166,630
Net income from continuing operations	123,401	2,009	--	125,410
Total assets[2]	5,509,358	70,641	271,220	5,851,219
Construction expenditures - excluding equity AFUDC	393,891	--	--	393,891

2003 (Dollars in Thousands)	Regulated Utility	Other	Reconciling Item	Puget Energy Total
Revenues[1]	$ 2,034,973	$ 6,043	$ --	$ 2,041,016
Depreciation and amortization	219,851	236	--	220,087
Income tax	69,823	952	--	70,775
Operating income	295,219	2,504	--	297,723
Interest charges, net of AFUDC	179,436	123	--	179,559
Net income from continuing operations[3]	119,313	438	(5,151)	114,600
Total assets[2]	5,290,497	75,196	343,031	5,708,724
Construction expenditures - excluding equity AFUDC	269,973	--	--	269,973

1 *Revenues for the Regulated Utility segment were reduced $108.7 million in 2003 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 consists of assets of InfrastruX which is presented as discontinued operations.*

3 *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 statement 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) 2005 QUARTER	FIRST	SECOND[3]	THIRD	FOURTH
Operating revenues	$ 741,653	$ 510,114	$ 490,383	$ 831,061
Operating income	110,534	51,919	47,528	93,180
Other income	1,164	1,598	1,422	4,125
Net income from continuing operations	72,093	11,967	5,912	56,308
Net income before cumulative effect of accounting change	71,075	13,895	5,911	64,915
Net income	71,075	13,895	5,911	64,844
Basic earnings per common share	$ 0.71	$ 0.14	$ 0.06	$ 0.60
Diluted earnings per common share	$ 0.71	$ 0.14	$ 0.06	$ 0.60

(Unaudited; dollars in thousands except per share amounts) 2004 QUARTER	FIRST	SECOND[1]	THIRD	FOURTH[2]
Operating revenues	$ 668,714	$ 423,123	$ 415,026	$ 692,012
Operating income	108,742	30,575	50,218	98,143
Other income	68	1,570	356	2,368
Net income loss from continuing operations	66,744	(9,720)	9,447	58,939
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)

1 *The second quarter 2004 includes a disallowance of $37.7 million or $24.5 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 *The second quarter 2005 includes a one-time true-up of previously reported gas cost of $5.0 million.*

PUGET SOUND ENERGY

(Unaudited; dollars in thousands) 2005 QUARTER	FIRST	SECOND[2]	THIRD	FOURTH
Operating revenues	$ 741,653	$ 510,114	$ 490,383	$ 831,061
Operating income	110,555	52,044	47,705	93,195
Other income	1,164	1,598	1,422	4,125
Net income before cumulative effect of accounting change	72,182	12,166	6,170	56,323
Net income	72,182	12,166	6,170	56,252

(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

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 second quarter 2005 includes a one-time true-up of previously reported gas cost of $5.0 million.*

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, 2005				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,670	$ 8,275	$ 7,871	$ 3,074
Reserve on wholesale sales	41,488	--	--	41,488
Deferred tax asset valuation allowance	17,988	--	1,913	16,075
Tenaska disallowance reserve	3,156	2,217	5,373	--
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
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	$ 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	--

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, 2005				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,670	$ 8,275	$ 7,871	$ 3,074
Reserve on wholesale sales	41,488	--	--	41,488
Tenaska disallowance reserve	3,156	2,217	5,373	--
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	--

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, 2005, 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, 2005 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, 2005.

Puget Energy's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, 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, 2005, 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, 2005, 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, 2005.

PSE's management assessment of the effectiveness of internal control over financial reporting as of December 31, 2005 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 2006 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 2006 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 AND RELATED SHAREHOLDER MATTERS

The following table sets forth information regarding Puget Energy common stock that may be issued upon the exercise of options, warrants and other rights granted to employees, consultants or directors under all of the Puget Energy existing equity compensation plans, as of December 31, 2005:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	40,000	$22.51	4,081,869 (1)(2)(3)(5)
Equity compensation plans not approved by security holders	260,000 (4)	$22.51 (4)	--
Total	300,000	$22.51	4,081,869

The table does not include 88,887 deferred stock units in the Company's deferred compensation plans that are payable in stock, plus cash for any fractional shares, of which all are currently vested.

(1) Includes 148,814 shares remaining available for issuance under Puget Energy's Employee Stock Purchase Plan.

(2) Includes 3,686,017 shares remaining available for issuance under Puget Energy's 2005 Long-Term Incentive Plan. Depending on the achievement level of performance goals, the outstanding performance share grants may be paid out at zero shares at a minimum achievement level, 907,983 shares at a target level or 1,588,747 shares at a maximum level. Because there is no exercise price associated with performance shares, such shares are not included in the weighted-average price calculation.

(3) In addition to stock options, Puget Energy may also grant stock awards, performance awards and other stock-based awards under the 2005 Long-Term Incentive Plan.

(4) Does not include stock options that were assumed by PSE in connection with its acquisition of Washington Energy Company. The assumed options are for the purchase of 2,379 shares of Puget Energy common stock and have a weighted-average exercise price of $23.11 per share. In the event that any assumed option is not exercised, no further option to purchase shares of common stock will be issued in place of such unexercised option.

(5) Includes 247,038 shares available for issuance under Puget Energy's Nonemployee Director Stock Plan (Nonemployee Director Plan). The Nonemployee Director Plan provides for automatic stock payments to each of Puget Energy's nonemployee directors. Each nonemployee director who is a nonemployee director at any time during a calendar year may receive a stock payment for all or a portion of the quarterly retainer paid to such director. Effective July 1, 2003, the number of shares that will be issued to each nonemployee director as a stock payment under the Nonemployee Director Plan is determined by dividing two-thirds of the quarterly retainer payable to such director for a fiscal quarter by the fair market value of Puget Energy's common stock on the last business day of that fiscal quarter. The Nonemployee Director Plan provides that the portion of the quarterly retainer that may be payable in stock will be determined by the Governance and Public Affairs Committee from time to time. A nonemployee director may elect to increase the percentage of his or her quarterly retainer that is paid in stock, up to 100%. A nonemployee director may also elect to defer the issuance of shares under the Nonemployee Director Plan in accordance with the terms of the plan.

SUMMARY OF EQUITY COMPENSATION PLANS NOT APPROVED BY SHAREHOLDERS

NON-PLAN GRANTS

On January 7, 2002, Puget Energy granted Stephen P. Reynolds, President and Chief Executive Officer of Puget Energy and Puget Sound Energy, two non-qualified stock option grants outside of any equity incentive plan adopted by Puget Energy (Non-Plan Option Grants). These stock option grants were an inducement to Mr. Reynolds' employment and in lieu of participation in the Company's Supplemental Executive Retirement Plan. One of the Non-Plan Option Grants made to Mr. Reynolds is for 150,000 shares of Puget Energy common stock and vests at a rate of 20% per year, for full vesting after five years. The other Non-Plan Option Grant made to Mr. Reynolds is for 110,000 shares of Puget Energy common stock and vests at a rate of 25% per year, for full vesting after four years. The exercise price of both Non-Plan Option Grants is $22.51 per share, equal to 100% of the fair market value of Puget Energy common stock on the date of grant. As of December 31, 2005, all of the 260,000 shares subject to the Non-Plan Option Grants remained outstanding. Except as expressly provided in the option agreement relating to each of the Non-Plan Option Grants, the Non-Plan Option Grants are subject to the terms and conditions of the Company's 2005 Long-Term Incentive Plan.

Upon a change of control (as defined in the Employment Agreement between Puget Energy and Mr. Reynolds, dated January 7, 2002), both Non-Plan Option Grants will become fully vested and immediately exercisable. If Mr. Reynolds' employment or service relationship with Puget Energy is terminated by Puget Energy without cause or by Mr. Reynolds with good reason, the vesting and exercisability of the Non-Plan Option Grants will be accelerated as follows: (1) the vesting and exercisability of the 150,000 share Non-Plan Option Grant will be accelerated such that the total number of shares vested and exercisable will be calculated as if the option had vested on a daily basis over the four-year period through the date of termination and (2) the vesting and exercisability of the 110,000 share Non-Plan Option Grant will be accelerated by two years. For purposes of the Non-Plant Option Grants, the terms "cause" and "good reason" have the meanings given to them in the Employment Agreement between Puget Energy and Mr. Reynolds, dated January 1, 2002.

Subject to the provisions regarding a change of control and termination of employment or service relationship by Puget Energy without cause or by Mr. Reynolds for good reason, as described above, upon termination of Mr. Reynolds' employment or service relationship with Puget Energy for any reason, the unvested portion of the Non-Plan Option Grants will terminate automatically and the vested portion may be exercised as follows: (1) generally, on or before the earlier of three months after termination and the expiration date of the option, (2) if termination is due to retirement, disability or death, on or before the earlier of one year after termination and the expiration date of the option, or (3) if death occurs after termination, but while the option is still exercisable, on or before the earlier of one year after the date of death and the expiration date of the option. Pursuant to an amendment to the Employment Agreement effective as of May 12, 2005, in consideration of Mr. Reynolds' remaining Chief Executive Officer at least through the date of the 2008 Annual Shareholders Meeting, the post-termination exercise period for each of the Non-Plan Option Grants was extended to January 7, 2012. In addition, a second amendment to the Employment Agreement effective February 9, 2006 changed the definition of change of control to conform to the change of control definition in the 2005 Long-Term Incentive Plan.

The Non-Plan Option Grants provide for the payment of the exercise price of options by any of the following means: (1) cash, (2) check, (3) tendering shares of Puget Energy's common stock, either actually or by attestation, already owned for at least six months (or any shorter period necessary to avoid a charge to Puget Energy's earnings for financial reporting purposes) that on the day prior to the exercise date have a fair market value equal to the aggregate exercise price of the shares being purchased, (4) delivery of a properly executed exercise notice, together with irrevocable instructions to a brokerage firm designated by Puget Energy to deliver promptly to Puget Energy the aggregate amount of sale or loan proceeds to pay the option exercise price and any withholding tax obligations that may arise in connection with the exercise or (5) any other method permitted by the plan administrator.

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:

	2005		2004	
(DOLLARS IN THOUSANDS)	PUGET ENERGY	PSE	PUGET ENERGY	PSE
Audit fees[1]	$ 2,023	$ 1,422	$ 2,084	$ 1,695
Audit related fees[2]	103	81	82	82
Tax fees[3]	45	33	59	55
Total	$ 2,171	$ 1,536	$ 2,225	$ 1,832

[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 2005 fees are estimated and include an aggregate amount of $1,094,000 and $1,021,000 billed to Puget Energy and PSE, respectively through December 31, 2005. The 2004 fees include an aggregate amount of approximately $1,251,000 and $1,156,000 billed to Puget Energy and PSE, respectively, through December 31, 2004.*

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

[3] *Consists of tax 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 an Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by an 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 registered public accounting firm. With respect to each proposed pre-approved service, the independent registered public accounting firm 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 pre-approval decision to an Audit Committee at its next scheduled meeting. The Audit Committees do not delegate responsibilities to pre-approve services performed by the independent registered public accounting firm to management.

For 2005 and 2004, all audit and non-audit services were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a) Documents filed as part of this report:

1) *Financial Statements.* See index on page 73.

2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 130, as required for the years ended December 31, 2005, 2004 and 2003, consist of the following:

II. Valuation of Qualifying Accounts

3) Exhibits - see index on page 139.

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.	PUGET SOUND ENERGY
/s/ Stephen P. Reynolds	/s/ Stephen P. Reynolds
Stephen P. Reynolds Chairman, President and Chief Executive Officer	Stephen P. Reynolds Chairman, President and Chief Executive Officer
Date: February 27, 2006	Date: February 27, 2006

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 (Puget Energy and PSE unless otherwise noted)	DATE
/s/ Stephen P. Reynolds (Stephen P. Reynolds)	Chairman, President and Chief Executive Officer	February 27, 2006
/s/ Bertrand A. Valdman (Bertrand A. Valdman)	Senior Vice President Finance and Chief Financial Officer	
/s/ James W. Eldredge (James W. Eldredge)	Vice President, 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 dated 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 Eighty-first 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; Exhibit 4.2 to Current Report on Form 8-K dated June 3, 2003; Exhibit 4.28 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393; and Exhibit 4.1 to Current Report on Form 8-K, dated May 23, 2005, Commission File No. 1-16305 and 1-4393).
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 Thirty-second Supplemental Indenture dated April 1, 2005, defining the rights of the holders of PSE's First Mortgage Bond.

* 4.23 Thirty-third Supplemental Indenture dated April 27, 2005, defining the rights of the holders of PSE's First Mortgage Bond.

4.24 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).

4.25 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).

4.26 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).

4.27 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).

4.28 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).

4.29 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).

* 4.30 Eighty-second Supplemental Indenture dated as of April 27, 2005 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 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).

10.31 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).

10.32 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).

10.33 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).

10.34 Amended and Restated Credit Agreement dated March 25, 2005 covering PSE and various banks named therein, Wachovia Bank National Association as administrative agent. (Exhibit 99.1 to Current Report on Form 8-K, dated March 29, 2005, Commission File No. 1-4393 and 1-16305).

10.35 Loan and Serving Agreement dated December 20, 2005, among PSE, PSE Funding, Inc., and J.P. Morgan Chase Bank as program agent (Exhibit 10.2 to the Current Report on Form 8-K dated December 22, 2005, Commission File No. 1-4393 and 1-16305).

10.36 Receivable Sale Agreement dated December 20, 2005, among PSE and PSE Funding, Inc. (Exhibit 10.1 to the Current Report on Form 8-K dated December 22, 2005, Commission File Nos. 1-16305 and 1-4393).

** 10.37 Puget Energy, Inc. Non-employee Director Stock Plan. (Appendix B to definitive Proxy Statement, dated March 7, 2005, Commission File No. 1-16305).

** 10.38 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.)

** 10.39 Puget Energy 2005 Long-Term Incentive Plan. (Appendix A to definitive Proxy Statement, dated March 7, 2005, Commission File No. 1-16305).

** 10.40 Amendment No. 1 to 2005 Long-Term Incentive Plan of Puget Energy, Inc. (Exhibit 10.1 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).

** 10.41 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).

** 10.42 First Amendment dated May 10, 2005 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 (Exhibit 10.3 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).

** 10.43 Second Amendment dated February 9, 2006 to employment agreement with S. P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of May 10, 2005 (Exhibit 10.2 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393)

** 10.44 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).

** 10.45	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).
** 10.46	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).
** 10.47	Nonqualified 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).
** 10.48	InfrastruX 2000 Stock Incentive Plan adopted January 26, 2001. (Exhibit 10.53 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.49	InfrastruX 2000 Stock Incentive Plan Stock Option Grant Notice adopted January 26, 2001. (Exhibit 10.54 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.50	Puget Sound Energy Amended and Restated Supplemental Executive Retirement Plan for Senior Management dated October 5, 2004. (Exhibit 10.55 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.51	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Key Employees dated January 1, 2003. (Exhibit 10.56 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.52	Puget Sound Energy Amended and Restated Deferred Compensation Plan for Nonemployee Directors dated October 1, 2000. (Exhibit 10.57 to Annual Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.53	Summary of Director Compensation (Exhibit 10.5 to Current Report on Form 8-K, filed May 12, 2005, Commission File Nos. 1-4393 and 1-16305).
** 10.54	Performance-Based Restricted Stock Award Agreement with S.P. Reynolds, Chief Executive Officer and President, dated May 12, 2005 (Exhibit 10.4 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).
** 10.55	Form of Amended and Restated Change of Control Agreement between Puget Sound Energy, Inc. and Executive Officers (Exhibit 10.3 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).
* 12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy (2001 through 2005).
* 12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy (2001 through 2005).
* 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.*