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, 2007

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

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	/X/	No	/ /

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

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

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 $2,754,398,000. The number of shares of Puget Energy, Inc.'s common stock outstanding at February 20, 2008 was 129,678,489 shares.

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

This 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
aMW	Average Megawatt
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
Consortium	Infrastructure investors led by Macquarie Infrastructure Partners, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management, Macquarie-FSS Infrastructure Trust and Macquarie Capital Group Limited
Dth	Dekatherm (one Dth is equal to one MMBtu)
Ecology	Washington State Department of Ecology
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FPA	Federal Power Act
GAAP	Generally Accepted Accounting Principles
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
InfrastruX	InfrastruX Group, Inc.
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 of the United States
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NPNS	Normal Purchase Normal Sale
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.
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
Tenaska	Tenaska Power Fund, L.P.
Washington Commission	Washington Utilities and Transportation Commission
WECC	Western Electricity Coordinating Council
WECO	Western Energy Company

FORWARD-LOOKING STATEMENTS

Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (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 and 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.

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

- 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 (natural gas and electric), licensing of hydroelectric operations and natural gas storage facilities, recovery of other capital investments, recovery of power and natural gas costs, recovery of regulatory assets and present or prospective wholesale and retail competition;
- Failure to comply with FERC or Washington Commission standards and/or rules, which could result in penalties based on the discretion of either commission;
- Failure to comply with electric reliability standards developed by the North American Electric Reliability Corporation (NERC) for users, owners and operators of the power system, which could result in penalties of up to $1.0 million per day per violation;
- Changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, emissions, natural resources, and fish and wildlife (including the Endangered Species Act);
- The ability to recover costs arising from changes in enacted federal, state or local tax laws through revenue in a timely manner;
- Changes in tax law, related regulations, or differing interpretation or enforcement of applicable law by the Internal Revenue Service (IRS) or other taxing jurisdiction, which could have a material adverse impact on the financial statements;
- Natural disasters, such as hurricanes, windstorms, earthquakes, floods, fires and landslides, which can interrupt service and/or cause temporary supply disruptions and/or price spikes in the cost of fuel and raw materials and impose extraordinary costs;
- Commodity price risks associated with procuring natural gas and power in wholesale markets;
- 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;
- Financial difficulties of other energy companies and related events, which may affect the regulatory and legislative process in unpredictable ways and also adversely affect the availability of and access to capital and credit markets and/or impact delivery of energy to PSE from it 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 natural gas distribution system failure, which may impact PSE’s ability to deliver energy supply to its customers;
- Changes in weather conditions in the Pacific Northwest, which could have effects on customer usage and PSE’s revenues, thus impacting net income;
- Weather, which can have a potentially serious impact on PSE’s ability to procure adequate supplies of natural gas, fuel or purchased power to serve its customers and on the cost of procuring such supplies;

- Variable hydro 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 natural gas or electric plant to operate as intended;
- The ability to renew contracts for electric and natural 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 power or natural gas to its customers and generating facilities;
- The ability to restart generation following a regional transmission disruption;
- Failure of the interstate natural gas pipeline delivering to PSE's system, which may impact PSE's ability to adequately deliver natural gas supply or electric power to its customers;
- The amount of collection, if any, of PSE's receivables from the California Independent System Operator (CAISO) and other parties and the amount of refunds found to be due from PSE to the CAISO or other parties;
- Industrial, commercial and residential growth and demographic patterns in the service territories of PSE;
- General economic conditions in the Pacific Northwest, which might impact customer consumption or affect PSE's accounts receivable;
- 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 God, terrorism, flu pandemic or similar significant events;
- Capital market conditions, including changes in the availability of capital or interest rate fluctuations;
- Employee workforce factors, including strikes, work stoppages, availability of qualified employees or the loss of a key executive;
- The ability to obtain insurance coverage and the cost of such insurance;
- Future losses related to corporate guarantees provided by Puget Energy as a part of the sale of its InfrastruX subsidiary;
- The ability to maintain effective internal controls over financial reporting and operational processes; and
- With respect to merger transactions Puget Energy announced on October 26, 2007:
  - The risk that the merger may not be consummated in a timely manner if at all, including due to the failure to receive shareholder approval or any required regulatory approvals;
  - The risk that the merger agreement may be terminated in circumstances that require Puget Energy to pay a termination fee of up to $40.0 million, plus out-of-pocket expenses of the acquiring entity and its members of up to $10.0 million (or if no termination fee is payable, up to $15.0 million);
  - Risks related to diverting management's attention from ongoing business operations;
  - The effect of the announcement of the merger on our business relationships, operating results and business generally, including our ability to retain key employees.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, Puget Energy and PSE undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. You are also advised to consult the quarterly reports on Form 10-Q and current reports on Form 8-K, as well as Item 1A-"Risk Factors" on 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 subsidiary, Puget Sound Energy, Inc. (PSE), a utility company. Puget Energy has no significant assets other than the stock of PSE. On October 26, 2007, Puget Energy announced a merger with a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management, Macquarie-FSS Infrastructure Trust and Macquarie Capital Group Limited (collectively, the Consortium). At the effective time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, shall be cancelled and shall be converted automatically into the right to receive $30.00 in cash, without interest.

The consummation of the merger is subject to the satisfaction or waiver of certain closing conditions, including approval of the transaction by Puget Energy's shareholders, the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the HSR Act) and the receipt of several regulatory approvals, including those from the Washington Utilities and Transportation Commission (Washington Commission) and the Federal Energy Regulatory Commission (FERC). The merger is expected to close during the fourth quarter 2008. On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX Group, Inc. (InfrastruX) and therefore the financial position and results of operations for InfrastruX are presented as discontinued operations. 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		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
Puget Sound Energy	99.6%	99.7%	99.7%	99.7%	103.3 %	91.7%	98.9%	99.0%	94.8%
InfrastruX[1]	0%	0%	0%	0%	0 %	6.1%	0%	0%	4.2%
Other[2]	0.4%	0.3%	0.3%	0.3%	(3.3)%	2.2%	1.1%	1.0%	1.0%

1 *InfrastruX was sold in May 2006 and is presented on a discontinued operations basis in 2005 and 2006 and therefore does not present operating revenue.*

2 *Includes subsidiaries of PSE and Puget Energy holding company operations. 2006 includes the impact of the establishment and funding of a charitable foundation.*

PUGET ENERGY STRATEGY

Puget Energy is the parent company of PSE, the oldest and largest electric and natural gas utility headquartered in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas transmission and distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural gas service in a cost effective manner through PSE.

PUGET SOUND ENERGY, INC.

PSE is a public utility incorporated in the state of Washington in 1960. PSE furnishes electric and natural 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, 2007, PSE had approximately 1,056,400 electric customers, consisting of 933,200 residential, 116,400 commercial, 3,800 industrial and 3,100 other customers; and approximately 729,500 natural gas customers, consisting of 673,600 residential, 53,100 commercial, 2,600 industrial and 100 transportation customers. At December 31, 2007, approximately 363,200 customers purchased both electricity and natural gas from PSE. In 2007, PSE added approximately 17,100 electric customers and 16,500 natural gas customers, representing annualized customer growth rates of 1.6% and 2.3%, respectively. During 2007, PSE's billed retail and transportation revenues from electric utility operations were derived 52.4% from residential customers, 40.6% from commercial customers, 5.6% from industrial customers and 1.4% from other customers. PSE's retail revenues from natural gas utility operations were derived 62.6% from residential customers, 30.0% from commercial customers, 4.8% from industrial customers and 2.6% from transportation customers in 2007. During this period the largest customer accounted for approximately 1.2% of PSE's operating revenues.

PSE is affected by various seasonal weather patterns and therefore, utility revenues and associated expenses are not generated evenly during the year. Energy usage varies seasonally and monthly primarily as a result of weather conditions. PSE 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 natural gas rates to recover variations in natural gas supply and transportation costs. PSE also has a Power Cost Adjustment (PCA) mechanism in retail electric rates to recover variations in electricity costs on a shared basis with customers.

In the five-year period ended December 31, 2007, PSE's gross electric utility plant additions were $2.2 billion and retirements were $365.4 million. In the same five-year period, PSE's gross gas utility plant additions were $766.0 million and retirements were $101.7 million. In the same five-year period, PSE's gross common utility plant additions were $178.0 million and retirements were $53.7 million. Gross electric utility plant at December 31, 2007 was approximately $5.9 billion, which consisted of 50.9% distribution, 34.1% generation, 5.7% transmission and 8.9% general plant and other. Gross gas utility plant at December 31, 2007 was approximately $2.3 billion, which consisted of 90.7% distribution and 8.7% general plant and other. Gross common utility general and intangible plant at December 31, 2007 was approximately $506.2 million.

INFRASTRUX GROUP, INC.

InfrastruX, is a utility construction services business. On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska). Puget Energy accounted for InfrastruX as a discontinued operation.

EMPLOYEES

At February 20, 2008, Puget Energy had no employees and PSE had approximately 2,600 full-time employees. Approximately 1,200 PSE employees are represented by the International Brotherhood of Electrical Workers Union (IBEW) or the United Association of Plumbers and Pipefitters (UA). The current labor contracts with the IBEW and UA run through March 31, 2010 and September 30, 2010, respectively.

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 information required by Item 101(e) of Regulation S-K is incorporated herein by reference to the material under "Available Information" in Item 10 of Part III of this annual report.

NEW YORK STOCK EXCHANGE CERTIFICATION

On May 22, 2007, the CEO of Puget Energy and PSE filed a Section 303A.12(a) CEO Certification with the New York Stock Exchange (NYSE). The CEO Certification attests that the CEO is not aware of any violations by the Company of the NYSE's Corporate Governance Listing Standards.

REGULATION AND RATES

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

FEDERAL REGULATION

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 had been an active participant in regional efforts to form an RTO/ISO in the Pacific Northwest since the issuance of Order No. 2000. PSE has continued to work with the Bonneville Power Administration (BPA) and other regional transmission owners to address the transmission related issues in the region via a new organization known as ColumbiaGrid.

The Energy Policy Act of 2005 (EPAct 2005) added a requirement for FERC to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable electric system reliability standards. FERC has certified the North American Electric Reliability Corporation (NERC) as the ERO to develop these standards subject to FERC review and approval. On March 16, 2007, FERC issued Order 693, "Mandatory Reliability Standards for the Bulk-Power System," which imposes penalties of up to $1.0 million per day per violation for failure to comply with new electric reliability standards. FERC approved 83 reliability standards developed by NERC. The 83 standards comprise 586 requirements and sub-requirements. PSE must comply with the standards and requirements which apply to the NERC functions for which PSE has registered. On June 18, 2007, the standards became mandatory and enforceable under federal law. Additional standards continue to be developed and will be adopted in coming months or years. PSE expects that the existing standards will change often as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement.

Per NERC and Western Electricity Coordinating Council (WECC) guidelines, users, owners and operators of the bulk power system that self-report non-compliance with any of the NERC standards and that submit mitigation plans to address the non-compliance will not be subject to sanctions if the mitigation plans were submitted on or before June 18, 2007 and approved by WECC. PSE's compliance with NERC standards will be audited at least every three years. The first such audit was conducted during the fourth quarter 2007.

STATE REGULATION

PSE's retail electric service is fully regulated by the Washington Commission. PSE is not aware of any proposals or prospects for retail deregulation in the state of Washington.

PSE's retail natural gas service is also regulated by the Washington Commission. Since 1986, PSE has been offering natural gas transportation as a separate service to industrial and commercial customers who choose to purchase their natural gas supply directly from producers and natural gas marketers. PSE earns similar margins on transportation service and large-volume, interruptible natural gas sales. Accordingly, the shifting of customers between sales and transportation service does not materially impact utility margins or net income.

On December 17, 2007, PSE and the Consortium filed a joint application with the Washington Commission seeking approval of the merger. A decision by the Washington Commission is expected on September 2, 2008. If approved, closing is expected to occur during the fourth quarter 2008.

ELECTRIC REGULATION AND RATES

Power Cost Adjustment 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 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 was limited to $40.0 million plus 1% of the excess. On January 5, 2007, the Washington Commission approved the continuation of the PCA mechanism under the same annual graduated scale without a cumulative cap for excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale:

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

1 *Over the four-year period July 1, 2002 through June 30, 2006, the Company's share of pre-tax power cost variations was capped at a cumulative $40 million plus 1% of the excess. Power cost variations after June 30, 2006 are apportioned on an annual basis, on the graduated scale without a cumulative cap.*

Electric General Rate Case. On December 3, 2007, PSE filed a general rate case with the Washington Commission which proposed an increase in electric rates of $174.5 million or 9.5% annually, effective November 3, 2008. PSE requested a weighted cost of capital of 8.6%, or 7.29% after-tax, and a capital structure that included 45.0% common equity with a return on equity of 10.8%. PSE expects an order to be issued by the Washington Commission no later than October 2008.

On January 5, 2007, the Washington Commission issued its order in PSE's electric general rate case filed in February 2006, approving a general rate decrease for electric customers of $22.8 million or 1.3% annually. The rates for electric customers became effective January 13, 2007. In its order, the Washington Commission approved a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4%. The Washington Commission had earlier approved (on June 28, 2006) a power cost only rate case (PCORC) increase of $96.1 million annually, effective July 1, 2006.

Power Cost Only Rate Case. A limited-scope proceeding called a PCORC was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission approved an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On March 20, 2007, PSE submitted a PCORC filing to request approval of an updated power cost baseline rate beginning September 2007. The PCORC filing also requested recovery of ownership and operating costs of the Goldendale generating facility (Goldendale) through retail electric rates. On May 23, 2007, PSE filed updated power costs due to changes in market conditions of natural gas and other costs which resulted in a revised proposed increase of $77.8 million or 4.4% annually. On July 5, 2007, a settlement agreement in this PCORC signed by PSE and certain other parties to the proceeding was filed with the Washington Commission, the terms of which included an electric rate increase of $64.7 million. On August 2, 2007, the Washington Commission approved the settlement agreement and authorized an increase in PSE's electric rates of $64.7 million or an average increase of 3.7% annually effective September 1, 2007. The investment in Goldendale was found prudent, thus allowing for recovery of certain ownership and operating costs through electric retail rates effective September 1, 2007 along with updating other power costs.

In accordance with the August 2, 2007 Washington Commission order approving the PCORC settlement, PSE and other parties agreed to conduct a collaborative stakeholder review of the PCORC process to consider the scope and timing of the PCORC mechanism. The collaborative review included but was not limited to: 1) the number of PCORCs that a company will be allowed to file in any given year; 2) the number and timing of updates that a company may submit in the PCORC process; 3) the items directly associated with power costs that may be included and considered in a PCORC filing; and 4) whether the number and timing of updates may vary depending on if other parties can easily verify. On December 12, 2007, the collaboration filed a final report with the Commission reporting that the parties were not able to reach agreement on revisions to the PCORC mechanism and that the parties will address such issues in the Company's pending general rate case filing.

On April 11, 2007, the Washington Commission approved PSE's petition for issuance of an accounting order that authorizes PSE to defer certain ownership and operating costs (and associated carrying costs) related to the Company's purchase of Goldendale during the period prior to inclusion in PSE's retail electric rates in the PCORC. The deferral is for the time period from March 15, 2007 through September 1, 2007. As of December 31, 2007, PSE had established a regulatory asset of $11.5 million. PSE anticipates recovery of the costs will begin no later than November 2008 as determined in PSE's next general rate case.

On October 20, 2005, the Washington Commission approved a PCORC filing that increased electric rates 3.7% or $55.6 million annually. Included in the increase is the recovery of capital and operating costs of the Hopkins Ridge wind generating facility (Hopkins Ridge). 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 $0.02 per kilowatt hour (kWh) for wind generation and may be subject to inflation adjustments over time. The tax credit can be claimed for ten years for a new wind project put into service prior to January 1, 2008. The use of the credit is restricted to offset only 25.0% of current taxes payable. 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 PTCs of the Hopkins Ridge project. This mechanism (a PTC Tracker) will pass through to the customer the actual PTCs of the Hopkins Ridge project as they are generated. The PTC Tracker would not be subject to the sharing bands in the PCA. The credits passed through to the customer will be adjusted by the carrying costs of unused PTCs. Since the customer receives the benefit of the tax credits as they are generated and the Company does not receive a credit from the Internal Revenue Service (IRS) until the tax credits are utilized, the Company is reimbursed its carrying costs for funds through this calculation.

GAS REGULATION AND RATES

Gas General Rate Case. On December 3, 2007, PSE filed a general rate case with the Washington Commission which proposed an increase in natural gas rates of $56.8 million or 5.3% annually, effective November 3, 2008. PSE requested a weighted cost of capital of 8.6%, or 7.29% after-tax, and a capital structure that included 45.0% common equity with a return on equity of 10.8%. PSE expects an order to be issued by the Washington Commission no later than October 2008.

On January 5, 2007, the Washington Commission issued its order in PSE's natural gas general rate case, granting an increase in natural gas rates of $29.5 million or 2.8% annually, effective January 13, 2007, which resulted in an increase in natural gas margin of approximately 9.8% annually. In its order the Washington Commission approved the same weighted cost of capital of 8.4%, or 7.06% after-tax, and capital structure that included 44.0% common equity with a return on equity of 10.4%, as allowed for the Company's electric operations.

Purchased Gas Adjustment. PSE has a PGA mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. Variations in natural gas rates are passed through to customers, therefore PSE's natural gas margin and net income are not affected by such variations. On September 26, 2007, the Washington Commission approved PSE's requested revisions to its PGA tariffs resulting in a rate decrease for natural gas customers of $148.1 million or 13.0% annually effective October 1, 2007. The rate decrease was the result of lower costs of natural gas in the forward market and a refund of the accumulated PGA payable balance over a 12-month period beginning October 1, 2007. The PGA rate change will decrease PSE's revenue but will not impact the Company's natural gas margins or net income as the decreased revenue will be offset by decreased purchased natural gas costs and decreased revenue sensitive taxes.

The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2007, 2006 and 2005:

EFFECTIVE DATE	PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUES (DOLLARS IN MILLIONS)
October 1, 2007	(13.0)%	$ (148.1)
October 1, 2006	10.2 %	95.1
October 1, 2005	14.7 %	121.6

ELECTRIC UTILITY OPERATING STATISTICS

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Generation and purchased power, MWh			
Company-controlled resources	8,623,094	6,845,323	6,902,040
Contracted resources	9,353,824	9,625,381	9,606,880
Non-firm energy purchased	7,473,458	8,185,198	7,299,139
Total generation and purchased power	25,450,376	24,655,902	23,808,059
Less: losses and Company use	(1,562,975)	(1,489,008)	(1,448,214)
Total energy sales, MWh	23,887,401	23,166,894	22,359,845

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Electric energy sales, MWh			
Residential	10,869,347	10,593,340	10,321,984
Commercial	9,226,215	8,939,155	8,647,478
Industrial	1,364,264	1,368,672	1,357,973
Other customers	96,217	78,078	105,388
Total energy billed to customers	21,556,043	20,979,245	20,432,823
Unbilled energy sales – net increase	78,303	119,800	40,015
Total energy sales to customers	21,634,346	21,099,045	20,472,838
Sales to other utilities and marketers	2,253,055	2,067,849	1,887,007
Total energy sales, MWh	23,887,401	23,166,894	22,359,845
Transportation, including unbilled	2,131,970	2,091,981	2,030,457
Electric energy sales and transportation, MWh	26,019,371	25,258,875	24,390,302

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Electric operating revenues by classes (thousands):			
Residential	$ 951,101	$ 788,237	$ 690,184
Commercial	748,824	702,754	629,008
Industrial	105,227	103,043	93,922
Other customers	57,482	66,470	76,153
Operating revenues billed to customers	1,862,634	1,660,504	1,489,267
Unbilled revenues – net increase	16,103	20,749	9,548
Total operating revenues from customers	1,878,737	1,681,253	1,498,815
Transportation, including unbilled	9,356	11,488	9,027
Sales to other utilities and marketers	109,736	85,004	105,027
Total electric operating revenues	$ 1,997,829	$ 1,777,745	$ 1,612,869

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Number of customers served (average):			
Residential	926,080	909,876	893,576
Commercial	115,577	111,672	111,587
Industrial	3,771	3,696	3,877
Other	2,965	2,637	2,426
Transportation	18	18	17
Total customers (average)	1,048,411	1,027,899	1,011,483

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Average kWh used per customer:			
Residential	11,737	11,643	11,551
Commercial	79,827	80,048	77,495
Industrial	361,778	370,312	350,264
Other	32,451	29,609	43,441
Average revenue billed per customer:			
Residential	$ 1,027	$ 866	$ 772
Commercial	6,479	6,293	5,637
Industrial	27,904	27,880	24,225
Other	19,366	25,207	31,390
Average retail revenues per kWh sold:			
Residential	$ 0.0875	$ 0.0744	$ 0.0669
Commercial	0.0812	0.0786	0.0727
Industrial	0.0771	0.0753	0.0692
Average retail revenue per kWh sold	0.0841	0.0763	0.0695
Heating degree days	4,823	4,476	4,489
Percent of normal – NOAA 30-year average	100.5%	93.3%	93.6%
Load factor[1]	58.9%	52.4%	57.4%

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

ELECTRIC SUPPLY

At December 31, 2007, PSE's electric power resources had a total capacity of approximately 4,719 megawatts (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. When it is more economical 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, 2007 and 2006 and energy production during the year:

	Peak Power Resources At December 31				Energy Production At December 31			
	2007		2006		2007		2006	
	MW	%	MW	%	MWh	%	MWh	%
Purchased resources:								
Columbia River PUD contracts[1]	1,073	22.7%	1,164	26.1%	5,810,416	22.8%	5,692,366	23.1%
Other hydroelectric[2]	168	3.6%	168	3.8%	570,639	2.2%	653,362	2.6%
Other producers[2]	944	20.0%	932	20.9%	2,964,199	11.6%	3,279,575	13.3%
Wind	50	1.1%	--	--	8,570	0.2%	--	--
Short-term wholesale energy purchases[3]	N/A	N/A	N/A	N/A	7,473,458	29.4%	8,185,276	33.2%
Total purchased	2,235	47.4%	2,264	50.8%	16,827,282	66.2%	17,810,579	72.2%
Company-controlled resources:								
Hydroelectric	236	5.0%	234	5.3%	1,154,234	4.5%	949,276	3.9%
Coal	677	14.3%	677	15.2%	5,142,912	20.2%	4,800,028	19.5%
Natural gas/oil[4]	1,192	25.3%	902	20.2%	1,310,625	5.1%	723,190	2.9%
Wind[5]	379	8.0%	379	8.5%	1,015,323	4.0%	372,829	1.5%
Total company-controlled	2,484	52.6%	2,192	49.2%	8,623,094	33.8%	6,845,323	27.8%
Total	4,719	100.0%	4,456	100.0%	25,450,376	100.0%	24,655,902	100.0%

1 *Net of 59 MW of capacity delivered to Canada pursuant to the provisions of a treaty between Canada and the US and Canadian Entitlement Allocation agreements.*
2 *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.*
3 *Short-term wholesale purchases net of resale of 2,253,055 MWh and 2,067,849 MWh account for 22.5% and 27.1% of energy production for 2007 and 2006, respectively.*
4 *Goldendale is included beginning February 21, 2007.*
5 *Wild Horse began commercial operations on December 22, 2006.*

INTEGRATED RESOURCE PLANS

PSE is required by the Washington Commission to file electric and natural gas Integrated Resource Plans (IRP) every two years. PSE filed its 2007 IRP on May 31, 2007 with the Washington Commission. The plan supports a strategy of significantly increasing energy efficiency programs, pursuing additional renewable resources (primarily wind) and additional base load natural gas fired generation to meet the growing needs of our customers. The 2007 IRP found that developing new coal resources without a commercially viable means of mitigating carbon emissions would not be prudent. PSE's IRP analysis anticipates the Company will need to acquire 550 additional MW of wind resources, 1,200 MW of natural gas combined cycle resources and 314 average MW (aMW) of additional energy efficiency resources by 2015. The actual resources acquired and ownership structure of such resources will be determined through the Company's resource acquisition program that examines individual specific acquisition and development opportunities.

In August 2006, PSE announced the selection of seven projects for further consideration and possible negotiation as a result of the 2005 Request for Proposal (RFP) process. PSE has completed three transactions, including the purchase of Goldendale, a four-year power purchase agreement for 150 MW of winter on-peak energy commencing in 2008 and a power purchase agreement executed on July 12, 2007 for a portion of the output of Klondike Wind Power III, LLC, a wind-powered electric generating facility in north-central Oregon which was completed in December 2007. Of the remaining four opportunities, PSE remains in discussion on one project and has discontinued discussions on the other three. In October 2007, PSE filed two draft RFPs with the Washington Commission seeking approval to continue expansion of its energy-efficiency programs and acquisition of power supplies. PSE released its final RFPs in mid-January 2008. The first RFP seeks to broaden and expand PSE's program for helping customers conserve energy. The second RFP asked outside power producers, marketers and power-plant developers to help PSE procure up to 1,340 aMW of new electricity resources by 2015.

Based on PSE's projected customer usage for electricity and its current electric generation resources, PSE expects that future energy needs will exceed current purchased and Company-controlled power resources. The expected aMW shortfall for the period 2008 through 2011 is as follows:

	2008	2009	2010	2011
Projected aMW shortfall[1]	412	222	304	517

1 *Monthly average energy shortfall based on forecast January loads and estimated using all energy resources under long-term contracts and Company-controlled facilities.*

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 additional generating resources.

COMPANY – CONTROLLED ELECTRIC GENERATION RESOURCES

At December 31, 2007, PSE owns or controls the following plants with an aggregate net generating capacity of 2,484 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
Frederickson 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
Goldendale	Natural gas combined cycle	277	2004
Frederickson Unit 1 (49.85% interest)	Natural gas combined cycle	137	2002
Encogen	Natural gas cogeneration	167	1993
Crystal Mountain	Internal combustion	3	1969
Upper Baker River	Hydroelectric	91	1959
Lower Baker River	Hydroelectric	79	1925; reconstructed 1960; upgraded 2001
Snoqualmie Falls	Hydroelectric	44	1898 to 1911 & 1957
Electron	Hydroelectric	22	1904 to 1929
Wild Horse	Wind	229	2006
Hopkins Ridge	Wind	150	2005
Total net capacity		2,484	

SUMAS COGENERATION FACILITY

On December 10, 2007, PSE signed an agreement to purchase the Sumas Cogeneration Facility (Sumas), a 125 MW capacity natural gas cogeneration facility in the state of Washington, from the Sumas Cogeneration Company, L.P. This purchase is anticipated to be finalized in the second half of 2008.

FERC HYDROELECTRIC PROJECTS AND LICENSES

As part of its hydroelectric operations, PSE is required to obtain operating 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 Federal Power Act (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's current annual license expires on April 30, 2008 and PSE submitted an application for a new license to FERC on April 30, 2004. On November 30, 2004, PSE and 23 parties (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 $360.0 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 additional regulatory approvals yet to be attained from various agencies and other contingencies that have yet to be resolved. FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain.

Snoqualmie Falls project. The Snoqualmie Falls project was granted a new 40-year operating license by FERC on June 29, 2004. On July 29, 2004, the Snoqualmie Tribe 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. Appeals to the U.S. Court of Appeals by the Snoqualmie Tribe and by PSE have been consolidated. Oral arguments were held on February 8, 2007. An adverse ruling from the Court or adverse action by FERC if the license issuance is remanded could impact PSE's future use of this generating asset. In addition, on December 6, 2007, PSE filed an application for a non-capacity amendment to the 2004 license. The application seeks to amend the license to account for technology improvements and hydrologic and other changes that occurred post-license. The ultimate outcome of the license amendment application remains uncertain.

White River project. The White River project was operated as a hydropower facility until 2004. PSE is actively seeking to sell the project and the municipal water rights associated with the project to one or more entities. In June 2003, the Washington State Department of Ecology (Ecology) approved an application for new municipal water rights related to the White River project reservoir. After an appeal in July 2004, this decision was remanded back to Ecology for further analysis of non-hydropower operations. On December 21, 2006, PSE entered into a Purchase and Sale Agreement with the Cascade Land Conservancy to sell certain rights and interests in a portion of former project properties; however, this agreement has lapsed and PSE is examining its options.

On April 7, 2004, the Washington Commission approved PSE's recovery on the unamortized White River plant investment. At December 31, 2007, the White River project net book value totaled $72.5 million, which included $41.9 million of net utility plant, $17.3 million of capitalized FERC licensing costs, $6.7 million of costs related to construction work in progress and $6.6 million related to dam operations and safety. On February 18, 2005, the Washington Commission approved the recovery of the White River net utility plant costs but did not allow current recovery of FERC licensing costs and other related costs until all costs associated with selling the White River plant and any sales proceeds are known. Any proceeds from the sale of the White River assets and water rights will reduce the balance of the deferred regulatory asset. Neither the outcome of this matter nor any potential associated financial impacts can be predicted at this time.

COLUMBIA RIVER ELECTRIC ENERGY SUPPLY CONTRACTS

During 2007, approximately 22.8% of PSE's energy output was obtained at an average cost of approximately $0.015 per kWh through long-term contracts with several of the Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River. PSE agrees to pay a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project. PSE's payments are not contingent upon the projects being operable.

As of December 31, 2007, the Company was entitled to purchase portions of the power output of the PUDs' projects as set forth:

Project	Contract Exp. Year	License Exp. Year	Company's Annual Amount Purchasable (Approximate) % of Output	Megawatt Capacity
Chelan County PUD:[1]				
Rock Island Project				
Original units	2012	2029	50.0	248
Additional units	2012	2029	50.0	
Rocky Reach Project	2011	2006	38.9	488
Douglas County PUD:				
Wells Project	2018	2012	29.9	251
Grant County PUD:[2,3]				
Priest Rapids Development	TBD	TBD	4.3	39
Wanapum Development	2009	TBD	10.8	106
Total				1,132

1 *On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25.0% of the output of Chelan's Rocky Reach and Rock Island hydro electric generating facilities located on the mid-Columbia River in exchange for PSE paying 25.0% of the operating costs of the facilities. 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). PSE made a non-refundable capacity reservation payment of $89.0 million as required by the agreements. The Washington Commission determined the prudence of PSE entering into the new Chelan contract and confirmed the treatment of the $89.0 million as a regulatory asset as part of its order in PSE's General Rate Case on January 5, 2007.*

2 *Under terms of the 2001 Grant contract extensions, 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 of 2005 for the Priest Rapids Development and will begin in November of 2009 for the Wanapum Development.*

3 *PSE's share of power from the 2001 contract 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 was 4.3% in 2007 and will be adjusted annually for the remaining term of the new contract.*

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 generally is not obligated to make payments under these contracts unless power is delivered.

Under a 1985 settlement agreement with BPA, PSE is entitled to receive exchange energy from BPA during the months of November through April, which amounts to 42 aMW of energy and 82 MW of capacity for contract year 2007-2008. BPA has an option to request that PSE deliver up to 42 aMW of exchange energy to BPA in all months except May, July and August for contract year 2007-2008. The contract terminates June 30, 2017, but may be terminated earlier under certain circumstances.

On October 1, 1989, PSE signed a contract with The Montana Power Company, now NorthWestern Energy, for 71 aMW of energy (97 MW of peak capacity) through December 2010. The contract deliveries are contingent on the combined availability of Colstrip Units 3 & 4. The contract payments consist of a fixed monthly payment and an energy payment based on 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 73.0%) for the contract year.

In January 1992, PSE executed an agreement with Pacific Gas & Electric Company (PG&E) to exchange 300 MW of capacity together with up to 413,000 megawatt hours (MWh) of energy seasonally each year. No payments are made under this agreement. PG&E provides power during the months of November through February and PSE provides power during the months of June through September. Each party may terminate the contract upon five year prior notice.

Electric Energy Supply Contracts and Agreements With Non-Utility Generators

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

As of December 31, 2007, the Company purchased the power output from the following:

Contract	Plant Type	Contract Exp. Year	Megawatt Capacity	Average Megawatts of Energy
March Point Cogeneration Company:				
March Point Phase I	Natural gas cogeneration	2011	80	70
March Point Phase II	Natural gas cogeneration	2011	60	53
Tenaska Washington Partners, LP	Natural gas cogeneration	2011	245	216
Total			385	339

Electric Transmission Contracts With Other Utilities

PSE has entered into numerous transmission contracts with BPA to integrate electric generation and contracted resources into PSE's system. These transmission contracts require PSE to pay for transmission service based on the contracted MW level of demand, regardless of actual use. Any costs incurred are recovered through the PCA mechanism.

Other agreements provide actual capacity ownership or capacity ownership rights. PSE's annual charges are also based on contracted MW volumes. Capacity on these agreements that is not committed is 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 have various terms and collectively have an aggregate demand limit in excess of 3,550 MW.

NATURAL GAS UTILITY OPERATING STATISTICS

Twelve Months ended December 31	2007	2006	2005
Gas operating revenues by classes (thousands):			
Residential	$ 756,188	$ 697,631	$ 592,361
Commercial firm	306,357	279,977	234,342
Industrial firm	46,805	43,994	38,380
Interruptible	67,560	68,753	56,928
Total retail gas sales	1,176,910	1,090,355	922,011
Transportation services	13,706	13,269	13,277
Other	17,413	16,494	17,227
Total gas operating revenues	$ 1,208,029	$ 1,120,118	$ 952,515

Twelve Months ended December 31	2007	2006	2005
Number of customers served (average):			
Residential	666,756	649,373	629,563
Commercial firm	52,067	51,007	50,148
Industrial firm	2,611	2,618	2,651
Interruptible	445	470	528
Transportation	124	122	129
Total customers	722,003	703,590	683,019

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Gas volumes, therms (thousands):			
Residential	556,837	533,370	510,026
Commercial firm	248,497	236,753	225,389
Industrial firm	40,472	41,185	38,576
Interruptible	64,944	65,016	61,769
Total retail gas volumes, therms	910,750	876,324	835,760
Transportation volumes	213,542	206,367	198,504
Total volumes	1,124,292	1,082,691	1,034,264

TWELVE MONTHS ENDED DECEMBER 31	2007	2006	2005
Working gas volumes in storage at year end, therms (thousands):			
Jackson Prairie	64,982	68,141	70,303
AECO hub - Canada	15,093	14,810	14,820
Clay Basin	87,454	91,090	38,857
Average therms used per customer:			
Residential	835	821	810
Commercial firm	4,773	4,642	4,494
Industrial firm	15,501	15,731	14,551
Interruptible	145,942	138,332	116,987
Transportation	1,722,113	1,691,533	1,538,791
Average revenue per customer:			
Residential	$ 1,134	$ 1,074	$ 941
Commercial firm	5,884	5,489	4,673
Industrial firm	17,926	16,804	14,478
Interruptible	151,819	146,283	107,818
Transportation	110,533	108,762	102,922
Average revenue per therm sold:			
Residential	$ 1.358	$ 1.308	$ 1.161
Commercial firm	1.233	1.183	1.040
Industrial firm	1.156	1.068	0.995
Interruptible	1.040	1.057	0.922
Average retail revenue per therm sold	1.292	1.244	1.103
Transportation	0.064	0.064	0.067
Heating degree days	4,823	4,476	4,489
Percent of normal – NOAA 30-year average	100.5%	93.3%	93.6%

NATURAL GAS SUPPLY

PSE currently purchases a blended portfolio of natural gas supplies ranging from long-term firm to daily 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 natural gas to serve its customers. All of PSE's natural gas supply is ultimately transported through the facilities of Northwest Pipeline GP (NWP), the sole interstate pipeline delivering directly into western Washington. Delivery of gas supply to PSE's natural gas system is therefore dependent upon the operations of NWP.

	2007		2006	
PEAK FIRM NATURAL GAS SUPPLY AT DECEMBER 31	Dth per Day	%	Dth per Day	%
Purchased gas supply:				
British Columbia	204,500	21.3%	235,000	24.3%
Alberta	60,000	6.2%	60,000	6.2%
United States	156,600	16.3%	145,700	15.1%
Total purchased natural gas supply	421,100	43.8%	440,700	45.6%
Purchased storage capacity:				
Clay Basin	91,000	9.5%	76,000	7.9%
Jackson Prairie	55,100	5.7%	55,100	5.7%
AECO hub - Canada	16,700	1.7%	16,700	1.7%
Liquefied natural gas	70,500	7.3%	70,500	7.3%
Total purchased storage capacity	233,300	24.2%	218,300	22.6%
Owned storage capacity:				
Jackson Prairie	294,700	30.7%	294,700	30.5%
Propane-air and other	12,500	1.3%	12,500	1.3%
Total owned storage capacity	307,200	32.0%	307,200	31.8%
Total peak firm natural gas supply	961,600	100.0%	966,200	100.0%
Other and commitments with third parties	(41,600)		(44,400)	
Total net peak firm natural gas supply	920,000		921,800	

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

PSE supplements its firm natural gas supply portfolio by purchasing natural gas, injecting it into underground storage facilities and withdrawing it during the peak winter heating season, for baseload and peak-shaving purposes. 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 natural gas system. Peaking needs are also met by using PSE-owned natural 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 natural 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.

NATURAL GAS SUPPLY PORTFOLIO

For the 2007-2008 winter heating season, PSE contracted for approximately 21.3% of its expected peak-day natural gas supply requirements from sources originating in British Columbia, Canada under a combination of long-term, medium-term and seasonal purchase agreements. Long-term natural gas supplies from Alberta represent approximately 6.2% of the peak-day requirements. Long-term and winter peaking arrangements with U.S. suppliers make up approximately 16.3% of the peak-day portfolio. The balance of the peak-day requirements is expected to be met with natural gas stored at Jackson Prairie, Clay Basin and AECO hub (AECO), LNG held at NWP's Plymouth facility and propane-air gas and other resources, which represent approximately 36.4%, 9.5%, 1.7%, 7.3% 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 January 2008 firm natural gas supply portfolio consisted of arrangements with 20 producers and natural gas marketers, with no single supplier representing more than 4.2% of expected peak-day requirements. Contracts have remaining terms ranging from less than one year to seven years.

During 2007, approximately 34.4% of natural gas supplies purchased by PSE originated in British Columbia while 18.5% originated in Alberta and 47.1% originated in the United States. PSE's firm natural gas supply portfolio has flexibility in its transportation arrangements so that some savings can be achieved when there are regional price differentials between natural gas supply basins. The geographic mix of suppliers and daily, monthly and annual take requirements permit some degree of flexibility in managing natural gas supplies during off-peak periods to minimize costs. Natural gas is marketed outside PSE's service territory (off-system sales) whenever on-system customer demand requirements permit.

NATURAL GAS STORAGE CAPACITY

PSE holds storage capacity in the Jackson Prairie and Clay Basin underground natural gas storage facilities adjacent to NWP's pipeline and at AECO in Alberta, Canada adjacent to Nova Gas Transmission, Ltd. (TransCanada-Alberta). These facilities represent 47.6% 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 natural gas over a relatively short time period. Combined with capacity contracted from NWP's one-third stake in Jackson Prairie, PSE has peak firm withdrawal capacity of over 349,000 Dekatherm (one Dekatherm, or Dth, is equal to one million British thermal units or MMBtu) per day and total firm storage capacity of over 8,800,000 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 natural gas requirements. PSE has been in the process of expanding the storage capacity at Jackson Prairie since March 2003 and plans to continue through 2010 or 2011. At the end of this project, PSE will have added approximately 2,000,000 Dth of additional working storage capacity. In order to meet the growing peaking requirements in the region, PSE and other owners of Jackson Prairie obtained FERC authorization on February 5, 2007 to increase deliverability of the project from 884,000 Dth per day to 1,196,000 Dth per day. PSE's share of this expansion, 104,000 Dth per day, is expected to cost $15.0 million and to be in service by November 2008. 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. PSE holds 13,400,000 Dth of Clay Basin capacity under two long-term contracts with remaining terms of five years and 12 years. PSE has exchanged 2,000,000 Dth of this Clay Basin capacity for 2,000,000 Dth of AECO storage capacity, which includes withdrawal capacity of approximately 16,700 Dth per day and terminates March 31, 2008. Net of this and other releases, PSE's maximum firm withdrawal capacity and total storage capacity at Clay Basin is approximately 91,000 Dth per day and exceeds 10,900,000 Dth, respectively.

LNG AND PROPANE-AIR RESOURCES

LNG and propane-air resources provide natural 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 natural gas as LNG at NWP's Plymouth facility, which is approximately three and one-half day's 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 natural gas per day for up to 12 days directly into PSE's distribution system. PSE owns and operates a LNG peaking facility in Gig Harbor with total capacity of 10,600 Dth.

NATURAL GAS TRANSPORTATION CAPACITY

PSE currently holds firm transportation capacity on pipelines owned by NWP, Gas Transmission Northwest (GTN), Nova Gas Transmission (NOVA), Foothills Pipe Lines (Foothills) and Westcoast Energy (Westcoast). GTN, NOVA, and Foothills are TransCanada companies. Accordingly, PSE pays fixed monthly demand charges for the right, but not the obligation, to transport specified quantities of natural gas from receipt points to delivery points on such pipelines each day for the term or terms of the applicable agreements.

PSE holds firm year-round capacity on NWP through various contracts. When market and operational conditions allow, PSE participates in the secondary pipeline capacity market to achieve savings for PSE's customers. PSE holds approximately 520,000 Dth per day of capacity on NWP that provides firm delivery to PSE's service territory. In addition, PSE holds approximately 414,000 Dth per day of seasonal firm capacity on NWP to provide for delivery of natural gas stored in Jackson Prairie and the Plymouth LNG facility during the heating season. PSE has committed to additional firm seasonal capacity of approximately 111,000 Dth per day commencing November 1, 2008 for a 20 year term. PSE has firm transportation capacity on NWP that supplies electric generating facilities with approximately 67,000 Dth per day, with a remaining term of 11 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 one 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 GTN's pipeline, totaling approximately 90,000 Dth per day, has a remaining term of 16 years.

PSE's firm transportation capacity on Westcoast's pipeline is approximately 97,000 Dth per day until October 31, 2012, then approximately 86,000 Dth per day until October 31, 2014, then approximately 41,000 Dth per day until October 31, 2017 and thereafter approximately 15,000 Dth per day until October 31, 2018. PSE has other firm transportation capacity on Westcoast's pipeline, which supplies the electric generating facilities, totaling approximately 22,000 Dth per day, with a remaining term of seven years. PSE has firm transportation capacity on NOVA and Foothills pipelines, totaling approximately 80,000 Dth per day, a portion of which has a remaining term of 15 years. PSE has annual rollover rights on the remainder of this capacity.

CAPACITY RELEASE

FERC provides 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. 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 reducing energy margins. The impact of load reductions is adjusted in rates at each general rate case.

Since 1995, PSE has been authorized by the Washington Commission to defer natural 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, natural gas energy efficiency expenditures have no impact on earnings.

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 mechanism, electric energy efficiency expenditures have no effect on earnings.

PSE's 2006-2007 two-year energy efficiency savings goals (40 aMW and 4.2 million therms) were set based on the 2005 IRP and in conjunction with the Conservation Resource Advisory Group (CRAG) per the terms of the 2002 Conservation Stipulation Agreement. The 2007 electric annual "baseline" savings goal of 18.3 aMW was agreed upon to reflect the new electric incentive-penalty mechanism approved in the Company's 2006 General Rate Case. The two-year natural gas savings goal to avoid a "penalty" mechanism remained at 4.2 million therms.

For the two-year period, 2006-2007, PSE achieved 44.4 aMW and over 5.0 million therms of cost-effective energy savings. For 2007 only, PSE achieved savings of 25.4 aMW and almost 2.7 million therms exceeding its goals and earning an electric incentive of $3.4 million (75% to be collected in 2008 and 25% subject to evaluation and collection in 2009) and avoiding any natural gas penalty.

In 2007, PSE and the CRAG met regularly to share and discuss plans for energy efficiency programs, set targets and budgets and agree on a course of action for 2008 and 2009. In setting these targets, PSE and the CRAG considered the energy efficiency resource potential identified in the Company's 2007 IRP, as well as individual program cost effectiveness and market conditions. The collaborative process resulted in establishing overall 2008-2009 biennial energy efficiency acquisition targets and budgets for 53.3 aMW for electric programs and 5.3 million therms for natural gas programs.

The biennial electric savings target was further disaggregated to annual targets, as required by electric incentive-penalty mechanism. Thus, PSE, in consultation with the CRAG, has established a 2008 incentive threshold target range of 22.2 aMW to 24.7 aMW. For 2008, an incentive will be paid to the Company upon achieving savings of greater than or equal to 24.7 aMW. Conversely, if the Company achieves savings of 22.2 aMW or less, a penalty will be assessed. The annual incentive threshold target range for 2009 will be set prior to year-end 2008.

The biennial natural gas savings target of 4.2 million therms is still subject to the penalty mechanism established in the 2002 Conservation Stipulation Agreement. If natural gas conservation savings are less than 75% of the minimum goal, PSE will be subject to a penalty of $0.75 million. If savings are between 75% and 89% of the minimum, the penalty is $0.5 million, and between 90% and 99% of the minimum, the penalty is $0.2 million.

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.

GREENHOUSE GAS POLICY

PSE recognizes the growing concern that increased atmospheric concentrations of greenhouse gases contribute to climate change. PSE believes that climate change is a very important issue that requires careful analysis and responses. PSE's policy is to take cost-effective measures to mitigate and/or offset greenhouse gas emissions from our energy activities while maintaining a dependable, cost-effective and diverse energy portfolio mix that will sustain our customers' needs now and into the future. PSE is taking and will continue to take appropriate steps to meet the goal of providing cost-effective and reliable energy while decreasing the impact on climate change through the implementation of these measures. The full PSE Greenhouse Gas Policy is available at www.pse.com.

REGULATION OF EMISSIONS

PSE facilities are subject to regulation of emissions, including PSE's interest in coal-fired, steam-electric generating plants at Colstrip, Montana and its combustion turbine units. There is no assurance that future environmental laws and regulations affecting sulfur dioxide, carbon monoxide particulate matter or nitrogen oxide emissions will not be more restrictive, 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.

EMISSIONS INVENTORY

During 2007, PSE's total electric retail load of 21.6 million MWh was served from a supply portfolio of owned and purchased resources. Since 2002, PSE has voluntarily undertaken an inventory of its greenhouse gas (GHG) emissions associated with this portfolio. Such inventory follows the protocol established by the World Resource Institute GHG Protocol (GHG Protocol). The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2006 were 13.5 million tons (CO2e). Approximately 43.7% of these emissions (approximately 5.9 million tons) are associated with PSE's ownership and contractual interests in the 2,200 MW Colstrip, Montana coal-fired steam electric generation facility (Colstrip).

Colstrip is a significant part of the diversified portfolio PSE owns and/or operates for its customers. Consequently, while Colstrip remains a significant portion of our overall GHG emissions, PSE's overall emissions strategy demonstrates a concerted effort to manage our customers' needs with an appropriate balance of new renewable generation, existing generation owned and/or operated by PSE and significant energy efficiency efforts.

With ongoing development of state and federal initiatives intended to address climate change, the challenge to develop strategic solutions is more complicated than ever. However, PSE believes that now is the time to act. Consequently, PSE included a carbon intensity goal into its most recent IRP that will adhere to the objectives of our recently published Greenhouse Gas Policy.

On May 18, 2005, the Environmental Protection Agency (EPA) enacted the Clean Air Mercury Rule (CAMR) that will permanently cap and reduce mercury emissions from coal-fired power plants. The Montana Board of Environmental Review approved a more stringent rule to limit mercury emissions from coal-fired plants on October 16, 2006 (0.9 lbs/TBtu, instead of the federal 1.4 lbs/TBtu). The Colstrip owners are still evaluating the potential impact of the new Montana rule and it is still unknown whether the new rule will be appealed. Preliminary treatment technology studies undertaken by the Colstrip owners estimate that PSE's portion of the costs to comply with the new rule could be as much as $75.0 million in construction expenditures, but this number could change as new information becomes available.

On June 15, 2005, the EPA issued the Clean Air Visibility Rule to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units, including presumptive limits for sulfur dioxide, particulate matter and nitrogen oxide controls for large units. In February 2007, Colstrip was notified by EPA that Colstrip Units 1 & 2 were determined to be subject to the BART requirements. PSE submitted a BART engineering analysis for Colstrip Units 1 & 2 in August 2007. PSE cannot yet determine the need for or costs of additional controls to comply with this rule.

FEDERAL ENDANGERED SPECIES ACT

Since 1991, a total of seventeen species of Northwest and Columbia River Basin salmon and steelhead have been listed as threatened or endangered species under the Endangered Species Act, which influences hydroelectric operations. While the most significant impacts have affected the Mid-Columbia PUDs, certain Endangered Species Act impacts may affect PSE operations, potentially representing cost exposure and operational constraints. PSE is actively engaging the federal agencies to address Endangered Species Act issues for PSE's generating facilities.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Puget Energy as of February 28, 2008 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	60	Chairman, President and Chief Executive Officer since May 2005; President and Chief Executive Officer, 2002 – 2005. Director since January 2002.
J. W. Eldredge	57	Vice President, Controller and Chief Accounting Officer since May 2007; Vice President, Corporate Secretary and Chief Accounting Officer 2005-2007; Corporate Secretary and Chief Accounting Officer 1999 – 2005.
D. E. Gaines	51	Vice President Finance and Treasurer since March 2002.
E. M. Markell	56	Executive Vice President and Chief Financial Officer since May 2007; Senior Vice President Energy Resources 2003 – 2007; Vice President Corporate Development, 2002 – 2003.
J. L. O'Connor	51	Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics and Compliance Officer since May 2007; Senior Vice President, General Counsel, Chief Ethics and Compliance Officer 2005-2007; Vice President and General Counsel, 2003 - 2005.

The executive officers of Puget Sound Energy as of February 28, 2008 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	60	Chairman, President and Chief Executive Officer since May 2005; Director since January 2002; President and Chief Executive Officer 2002 – 2005.
J. W. Eldredge	57	Vice President, Controller and Chief Accounting Officer since May 2007; Vice President, Corporate Secretary, Controller and Chief Accounting Officer 2001-2007.
D. E. Gaines	51	Vice President Finance and Treasurer since March 2002.
K. J. Harris	43	Executive Vice President and Chief Resource Officer since May 2007; Senior Vice President Regulatory Policy and Energy Efficiency 2005-2007; Vice President Regulatory and Government Affairs, 2003 – 2005; Vice President Regulatory Affairs, 2002 – 2003.
E. M. Markell	56	Executive Vice President and Chief Financial Officer since May 2007; Senior Vice President Energy Resources 2003-2007; Vice President Corporate Development, 2002 – 2003.
J. L. O'Connor	51	Senior Vice President, General Counsel, Corporate Secretary and Chief Ethics and Compliance Officer since May 2007; Senior Vice President, General Counsel, Chief Ethics and Compliance Officer 2005-2007; Vice President and General Counsel, 2003 – 2005.
B. A. Valdman	45	Executive Vice President and Chief Operating Officer since May 2007; Senior Vice President Finance and Chief Financial Officer 2003-2007. Prior to joining PSE, he was a Managing Director with JP Morgan Securities, Inc., 2000 – 2003.

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.

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 rates that it charges its customers are 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 the regulatory authority of FERC with respect to the transmission of electric energy, the sale 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.

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. In addition, the Washington Commission decides what level of expense and investment is 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 PCA MECHANISM BY WHICH VARIATIONS IN PSE'S POWER COSTS ARE APPORTIONED BETWEEN PSE AND ITS CUSTOMERS IS NO LONGER SUBJECT TO A CAP, WHICH COULD RESULT IN SIGNIFICANT INCREASES IN PSE'S EXPENSES.

PSE has a PCA mechanism that provides for recovery of power costs from customers or refunding of power cost savings to customers, as those costs vary from the "power cost baseline" level of power costs which are set in part based on normalized assumptions about weather and hydro conditions. Excess power costs or power cost savings will be apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism. Beginning after June 30, 2006, PSE's share of power cost variations is no longer capped. As a result, if power costs are significantly higher than the baseline level, PSE's expenses could significantly increase.

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 some or all 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.

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 natural 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, natural 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.

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 risk, 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. 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, modified, or whether PSE will be willing to meet the relicensing requirements to continue operating these hydroelectric projects.

COSTS OF COMPLIANCE WITH ENVIRONMENTAL, CLIMATE CHANGE AND ENDANGERED SPECIES LAWS ARE SIGNIFICANT AND THE COST OF COMPLIANCE WITH NEW AND EMERGING LAWS AND REGULATIONS AND THE INCURRENCE OF ASSOCIATED LIABILITIES COULD ADVERSELY AFFECT PSE'S RESULTS OF OPERATIONS.

PSE's operations are subject to extensive federal, state and local laws and regulations relating to environmental, climate change and endangered species protection. To comply with these legal requirements, PSE must spend significant sums on measures including resource planning, remediation, monitoring, pollution control equipment and emissions related abatement and fees. New environmental, climate change 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, climate change and endangered species expenditures made by PSE in the future. 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. In addition, PSE may not be able to recover all of its costs for such expenditures through electric and natural gas rates at current levels in the future.

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 or during the time the facility was owned or operated by PSE. 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.

Specific to climate change, Washington State has adopted both a renewable portfolio standard and greenhouse gas legislation, including an emission performance standard provision. Recent U.S. Supreme Court decisions related to climate change have also drawn greater attention to this issue at the federal, state and local level. PSE cannot yet determine the costs of compliance with the recently enacted legislation.

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 on reasonable terms, its ability to pursue improvements or acquisitions, including generating capacity, which may be relied on for future growth and to otherwise implement its strategy, could be adversely affected.

Capital and credit 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.

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 negative 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 provisions in its credit facilities 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 natural 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, all of which would expose PSE to additional costs.

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 as well as conservation efforts 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, individually or in the aggregate, will not materially and adversely affect PSE's financial condition, results of operations or liquidity.

THE COMPANY MAY BE NEGATIVELY AFFECTED BY ITS INABILITY TO ATTRACT AND RETAIN PROFESSIONAL AND TECHNICAL EMPLOYEES.

The Company's ability to implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers in an aging workforce. Without a skilled workforce, the Company's ability to provide quality service to PSE's customers and meet regulatory requirements will be challenged and could affect earnings.

THE COMPANY MAY BE ADVERSELY AFFECTED BY EXTREME EVENTS IN WHICH THE COMPANY IS NOT ABLE TO PROMPTLY RESPOND AND REPAIR THE ELECTRIC AND GAS INFRASTRUCTURE SYSTEM.

The Company must maintain an emergency planning and training program to allow the Company to quickly respond to extreme events. Without emergency planning, the Company is subject to availability of outside contractors during an extreme event which may impact the quality of service provided to PSE's customers. In addition, a slow response to extreme events may have an adverse affect on earnings as customers may be without electricity and natural gas for an extended period of time.

THE COMPANY MAY BE NEGATIVELY AFFECTED BY UNFAVORABLE CHANGES IN THE TAX LAWS OR THEIR INTERPRETATION.

Changes in tax law, related regulations, or differing interpretation or enforcement of applicable law by the Internal Revenue Service or other taxing jurisdiction could have a material adverse impact on the Company's financial statements. The tax law, related regulations and case law are inherently complex. The Company must make judgments and interpretations about the application of the law when determining the provision for taxes. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. The Company's tax obligations include income, real estate, sales and use, business and occupation and employment-related taxes and ongoing appeals issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the taxing authorities.

RISKS RELATING TO PUGET ENERGY'S PROPOSED MERGER AND CORPORATE STRUCTURE

THERE ARE RISKS IF THE COMPANY DOES NOT COMPLETE THE PROPOSED MERGER WITH THE CONSORTIUM.

If the merger the Company announced on October 26, 2007 is not completed for any reason, Puget Energy will remain an independent public company and the common stock will continue to be listed and traded on the New York Stock Exchange. While we expect that management will operate the business in a manner similar to that in which it is being operated today, if the merger is not completed, Puget Energy may suffer negative financial ramifications, including the following:

- The current market price of Puget Energy's common stock may reflect a market assumption that the merger will occur, and a failure to complete the merger could result in a negative perception by investors in Puget Energy generally and could cause a decline in the market price of Puget Energy's common stock. This could affect Puget Energy's ability to access the equity markets to fund PSE's construction program and working capital needs.
- Puget Energy might be required to pay an up to $40.0 million termination fee, and up to $10.0 million of expenses, to the Consortium, which could adversely impact liquidity (or if no termination fee is payable, up to $15.0 million).

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, 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 restated articles of incorporation and electric and natural 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 shareholders 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.

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 natural 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 and Proceeding Relating to the Proposed Merger.

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

None.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 20, 2008, there were approximately 34,100 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 2007 and 2006. Puget Energy and its predecessor companies have paid dividends on common stock each year since 1943 when such stock first became publicly held.

	2007			2006		
	Price Range		Dividends	Price Range		Dividends
Quarter Ended	High	Low	Paid	High	Low	Paid
March 31	$ 25.84	$ 24.00	$ 0.25	$ 21.68	$ 20.26	$ 0.25
June 30	26.91	23.58	0.25	21.62	20.13	0.25
September 30	25.38	22.47	0.25	22.86	21.20	0.25
December 31	28.60	23.40	0.25	25.91	22.72	0.25

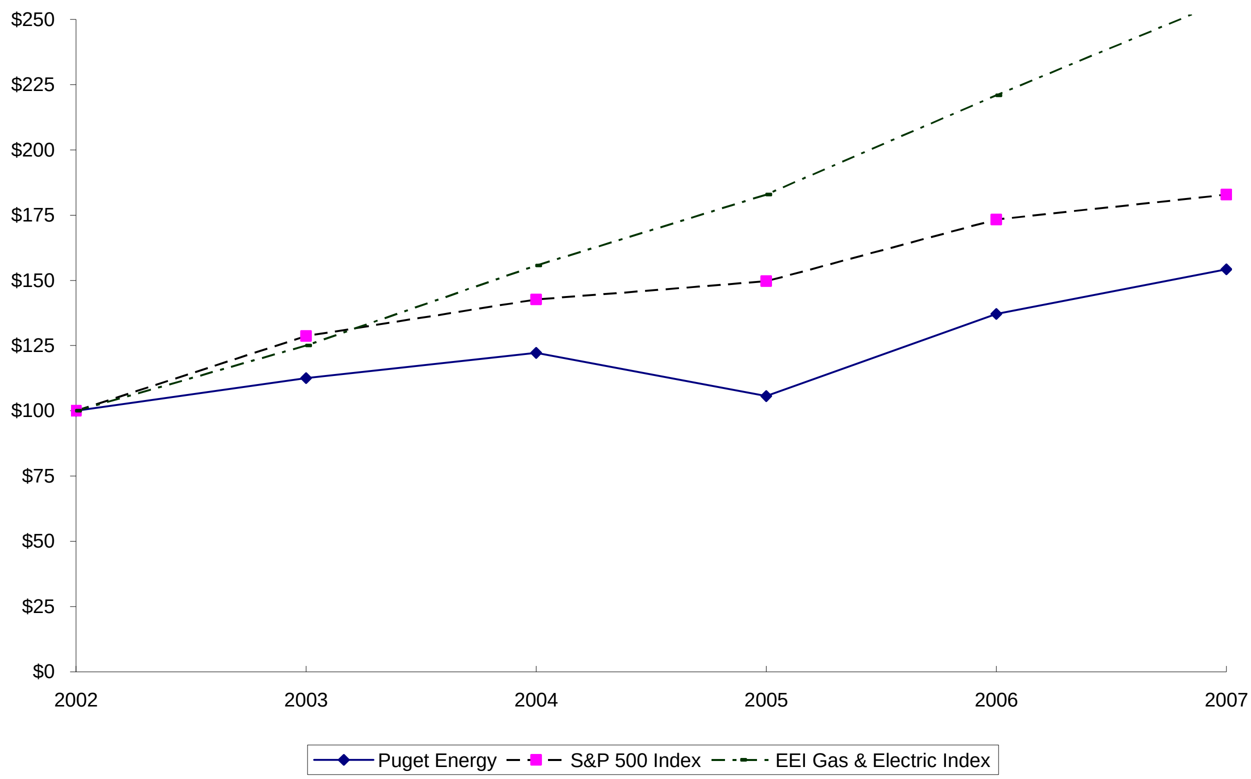
The amount and payment of future dividends will depend on Puget Energy’s financial condition, results of operations, capital requirements and other factors deemed relevant by Puget Energy’s Board of Directors. The Board of Directors’ current policy is to pay out approximately 60.0% of normalized utility 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 Restated Articles of Incorporation and electric and natural gas mortgage indentures. Under the most restrictive covenants of PSE, earnings reinvested in the business unrestricted as to payment of cash dividends were approximately $481.5 million at December 31, 2007.

STOCK PRICE PERFORMANCE

The chart below compares the five-year cumulative total shareholder return (share price appreciation plus reinvested dividends) of Puget Energy common stock to the cumulative total return of the Standard & Poor's 500 Stock Index (S&P 500) and the Edison Electric Institute (EEI) Combination Gas & Electric Investor-Owned Utilities Index.

Five-Year Cumulative Total Return



PUGET ENERGY SHAREHOLDER RETURN	2002	2003	2004	2005	2006	2007
PSD	$ 100.00	$ 112.61	$ 122.21	$ 105.65	$ 137.12	$ 154.25
EEI Gas & Electric Index	$ 100.00	$ 125.01	$ 155.74	$ 182.93	$ 220.94	$ 257.40
S&P 500 Index	$ 100.00	$ 128.69	$ 142.69	$ 149.70	$ 173.33	$ 182.85

This comparison assumes $100 was invested on December 31, 2002 in: (a) Puget Energy common stock; (b) the S&P 500 Stock Index; and (c) the EEI Combination Gas & Electric Investor-Owned Utilities Index. The graph then observes, in each case, stock price growth and dividends paid (assuming dividends were reinvested) over five years. The returns shown on the graph do not necessarily predict future performance.

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	2007	2006	2005	2004	2003
Operating revenue	$ 3,220,147	$ 2,907,063	$ 2,578,008	$ 2,202,333	$ 2,046,998
Operating income	441,034	420,851	390,297	362,766	363,020
Income from continuing operations	184,676	167,224	146,283	125,410	114,600
Net income	184,464	219,216	155,726	55,022	116,197
Basic earnings per common share from continuing operations	1.57	1.44	1.43	1.26	1.21
Basic earnings per common share	1.57	1.89	1.52	0.55	1.23
Diluted earnings per common share from continuing operations	1.56	1.44	1.42	1.26	1.20
Diluted earnings per common share	1.56	1.88	1.51	0.55	1.22
Dividends per common share	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Book value per common share	19.45	18.15	17.52	16.24	16.71
Total assets at year end	$ 7,598,736	$ 7,066,039	$ 6,609,951	$ 5,851,219	$ 5,708,724
Long-term debt	2,428,860	2,608,360	2,183,360	2,069,360	1,955,347
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	1,889	1,889
Junior subordinated notes	250,000	--	--	--	--
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	--	37,750	237,750	280,250	280,250

PUGET SOUND ENERGY
SUMMARY OF OPERATIONS
(DOLLARS IN THOUSANDS)

YEARS ENDED DECEMBER 31	2007	2006	2005	2004	2003
Operating revenue	$ 3,220,147	$ 2,907,063	$ 2,578,008	$ 2,202,333	$ 2,046,998
Operating income	450,384	422,682	391,650	363,748	363,365
Net income for common stock	191,127	176,740	146,769	126,192	114,735
Total assets at year end	$ 7,592,210	$ 7,061,413	$ 6,339,800	$ 5,564,087	$ 5,368,048
Long-term debt	2,428,860	2,608,360	2,183,360	2,064,360	1,950,347
Preferred stock subject to mandatory redemption	1,889	1,889	1,889	1,889	1,889
Junior subordinated notes	250,000	--	--	--	--
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	--	37,750	237,750	280,250	280,250

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 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 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" and "Risk Factors" 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, Inc. (Puget Energy) is an energy services holding company and all of its operations are conducted through its subsidiary Puget Sound Energy, Inc. (PSE), a regulated electric and natural gas utility company. Until May 7, 2006, Puget Energy owned a 90.9% interest in InfrastruX Group, Inc. (InfrastruX), a utility construction and services company that was sold to an affiliate of Tenaska Power Fund, L.P. (Tenaska). Puget Energy is dependent upon the results of PSE since PSE is its most significant asset. PSE is the largest electric and natural gas utility in the state of Washington, primarily engaged in the business of electric transmission, distribution, generation and natural gas distribution. Puget Energy's business strategy is to generate stable earnings and cash flow by offering reliable electric and natural gas service in a cost effective manner through PSE. An overview of significant recent developments affecting Puget Energy is provided below.

On October 26, 2007, Puget Energy announced that it had entered into a definitive Agreement and Plan of Merger, dated as of October 25, 2007, pursuant to which Puget Energy will be acquired by a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and which also includes Alberta Investment Management, Macquarie-FSS Infrastructure Trust and Macquarie Capital Group Limited (collectively, the Consortium). At the effective time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, shall be cancelled and shall be converted automatically into the right to receive $30.00 in cash, without interest.

The consummation of the merger is subject to the satisfaction or waiver of certain closing conditions, including the approval of the transaction by the affirmative vote of two-thirds of the votes entitled to be cast thereon by Puget Energy's shareholders, the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the HSR Act) and the receipt of required regulatory approvals. On December 17, 2007, PSE and the Consortium filed a joint application seeking approval of the merger with the Washington Utilities and Transportation Commission (Washington Commission). A decision by the Washington Commission is expected on September 2, 2008. If approved, closing is expected to occur during the fourth quarter 2008. On January 29, 2008, PSE and the Consortium filed an application with the Federal Energy Regulatory Commission (FERC) seeking approval of the proposed merger pursuant to section 203 of the Federal Power Act. A decision by FERC is expected by May 29, 2008.

The merger agreement contains termination rights for both Puget Energy and the Consortium under certain circumstances. In the event Puget Energy elects to terminate the merger agreement under specified circumstances, it would be required to pay to the acquiring entity either $30.0 million if the termination is based on the submission of an alternative proposal meeting certain requirements by a party with whom Puget Energy had been in discussions prior to December 10, 2007, or $40.0 million if such fee becomes payable in all other circumstances, plus, in each case, documented out-of-pocket expenses of the Consortium of up to $10.0 million. In addition, Puget Energy may be required to pay the Consortium documented out-of-pocket expenses incurred by the Consortium not in excess of $15.0 million if the merger agreement is terminated due to a breach of the terms of the Merger Agreement by Puget Energy and such breach is incurable or has not been cured within a specified time. The acquiring entity may be required to pay Puget Energy an amount equal to $130.0 million if the merger agreement is terminated due to a breach of the terms of the merger agreement by the acquiring entity and such breach is incurable or has not been cured within a specified time.

Puget Energy faces uncertainties in the future regarding both electric and natural gas customer growth and sales growth. The number of electric customers is expected to continue to grow at a rate of growth based on a forecasted slowing of regional population growth. Aside from the impact of fluctuations in weather, residential electric use per customer is expected to continue a long-term trend of slow decline based on continued energy efficiency improvements combined with the impact of higher retail rates. Electric residential usage per customer in 2007 was higher than 2006 due to colder weather.

The number of natural gas customers is expected to grow at rates slightly above electric customers due to the continued opportunity for conversion of existing electric customers to natural gas. Aside from weather impacts, residential natural gas use per customer is also expected to continue a long-term trend of decline based on continued energy efficiency improvements. Natural gas residential usage per customer in 2007 was higher than 2006 due to colder weather.

Puget Sound Energy. PSE generates revenues primarily from the sale of electric and natural gas services to residential and commercial customers within Washington State. PSE's operating revenues and associated expenses are not generated evenly throughout 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 and subsequently higher power costs during the winter 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.

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

On December 3, 2007, PSE filed a general rate case with the Washington Commission which proposed an increase in electric rates of $174.5 million or 9.5% annually and an increase in natural gas rates of $56.8 million or 5.3% annually, effective November 3, 2008. A decision is expected in October 2008.

PSE's main business objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE seeks to become more energy efficient and environmentally responsible in its energy supply portfolio on an ongoing basis. PSE filed its Integrated Resource Plan (IRP) on May 31, 2007 with the Washington Commission. The plan supports a strategy of significantly increasing energy efficiency programs, pursuing additional renewable resources (primarily wind) and additional base load natural gas fired generation to meet the growing needs of its customers. In October 2007, PSE filed two draft Request for Proposals (RFPs) with the Washington Commission to continue expansion of its energy-efficiency programs and power supplies. PSE has issued the RFPs and expects bids to be submitted by the end of February 2008 with a short list of projects identified by mid-2008. PSE's previous IRP and RFP in 2005 resulted in the selection of seven projects for further consideration and possible negotiation. PSE has completed three transactions, including the purchase of the Goldendale generating facility (Goldendale), a four-year power purchase agreement for 150 megawatts (MW) of winter on-peak energy commencing in 2008 and a power purchase agreement for a portion of the output of Klondike Wind Power III, LLC, a wind-powered electric generating facility in north-central Oregon. Of the remaining four opportunities, PSE remains in discussion on one project and has discontinued discussions on the other three.

NON-GAAP FINANCIAL MEASURES

The following discussion includes financial information prepared in accordance with generally accepted accounting principles (GAAP), as well as two other financial measures, Electric Margin and Gas Margin, that are considered "non-

GAAP financial measures." Generally, a non-GAAP financial measure is a numerical measure of a Company's financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. The presentation of Electric Margin and Gas Margin is intended to supplement investors' understanding of the Company's operating performance. Electric Margin and Gas Margin are used by the Company to determine whether the Company is collecting the appropriate amount of energy costs from its customers to allow recovery of operating costs. Our Electric Margin and Gas Margin measures may not be comparable to other companies' Electric Margin and Gas Margin measures. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiary PSE and until May 7, 2006, InfrastruX. Net income in 2007 was $184.5 million on operating revenues from continuing operations of $3.2 billion as compared to $219.2 million on operating revenues from continuing operations of $2.9 billion in 2006 and $155.7 million on operating revenues from continuing operations of $2.6 billion in 2005. Income from continuing operations in 2007 was $184.7 million as compared to $167.2 million in 2006 and $146.3 million in 2005. Net income for 2006 and 2005 includes the results of discontinued operations for InfrastruX.

Basic earnings per share in 2007 was $1.57 on 117.7 million weighted-average common shares outstanding as compared to $1.89 on 116.0 million weighted-average common shares outstanding in 2006 and $1.52 on 102.6 million weighted-average common shares outstanding in 2005. Diluted earnings per share in 2007 was $1.56 on 118.3 million weighted-average common shares outstanding as compared to $1.88 on 116.5 million weighted-average common shares outstanding in 2006 and $1.51 on 103.1 million weighted-average common shares outstanding in 2005. Included in basic earnings per share was $0.45 and $0.09 for 2006 and 2005, respectively, related to discontinued operations. Included in diluted earnings per share was $0.44 and $0.09 for 2006 and 2005, respectively, related to discontinued operations.

Net income for 2007 was positively impacted by higher energy margins driven by increased sales volumes and favorable hydroelectric conditions. Net income was negatively impacted by higher operation and maintenance expense, taxes other than income taxes net of revenue sensitive taxes and increases in depreciation and interest expenses, including costs related to the addition of new generating resources and energy delivery infrastructure investments. During the fourth quarter 2007, Puget Energy incurred $8.1 million in costs related to the proposed merger with the Consortium. Net income in 2006 was positively impacted by income from discontinued operations of InfrastruX of $51.9 million (after-tax). The income from discontinued operations included a gain on disposal of $29.8 million (after-tax) resulting from the sale of InfrastruX. The increase was partially offset by establishment and funding of a charitable foundation of $15.0 million ($9.75 million after-tax). Puget Energy's income from discontinued operations for 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10.0 million related to the anticipated realization of a deferred tax asset associated with the sale of the business.

2007 COMPARED TO 2006

PUGET SOUND ENERGY

Energy Margins. The following table displays the details of electric margin changes from 2006 to 2007. 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 2007	2006	CHANGE	PERCENT CHANGE
Electric operating revenue[1]	$ 1,997.8	$ 1,777.7	$ 220.1	12.4 %
Less: Other electric operating revenue	(41.9)	(51.8)	9.9	19.1
Add: Other electric operating revenue – gas supply resale	1.5	16.4	(14.9)	(90.9)
Total electric revenue for margin	1,957.4	1,742.3	215.1	12.3
Adjustments for amounts included in revenue:				
Pass-through tariff items	(43.0)	(35.9)	(7.1)	(19.8)
Pass-through revenue-sensitive taxes	(133.6)	(117.4)	(16.2)	(13.8)
Net electric revenue for margin	1,780.8	1,589.0	191.8	12.1
Minus power costs:				
Purchased electricity[1]	(895.6)	(917.8)	22.2	2.4
Electric generation fuel[1]	(143.4)	(97.3)	(46.1)	(47.4)
Residential exchange[1]	52.4	163.6	(111.2)	(68.0)
Total electric power costs	(986.6)	(851.5)	(135.1)	(15.9)
Electric margin[2]	$ 794.2	$ 737.5	$ 56.7	7.7 %

1 *As reported on PSE's Consolidated Statement of Income.*

2 *Electric margin does not include any allocation for amortization/depreciation expense or electric generation operation and maintenance expense.*

Electric margin increased $56.7 million in 2007 as compared to 2006. The increase was primarily due to recovery of ownership and operating costs of new generation facilities included in the power cost only rate case (PCORC) rate increase of 3.7% effective September 1, 2007 and in the general rate decrease of 1.3% effective January 13, 2007, which increased electric margin by $46.2 million. The increase in electric margin also benefited from higher production of low cost hydroelectric power and company-owned generating facilities which resulted in a $10.3 million increase in electric margin due to overrecovery of power costs in 2007 as compared to 2006 and a $16.4 million increase in margin due to an increase in retail sales volume of 2.5%. These increases were slightly offset by a $16.9 million decrease in margin due to an increase of Production Tax Credits (PTCs) provided to customers. PTCs provided to customers through lower rates are recovered through a lower effective tax rate.

The following table displays the details of gas margin changes from 2006 to 2007. Gas margin is natural gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of natural gas purchased, including natural gas transportation costs to bring natural gas to PSE's service territory.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2007	2006	CHANGE	PERCENT CHANGE
Gas operating revenue[1]	$ 1,208.0	$ 1,120.1	$ 87.9	7.8%
Less: Other gas operating revenue	(17.4)	(16.5)	(0.9)	(5.5)
Total gas revenue for margin	1,190.6	1,103.6	87.0	7.9
Adjustments for amounts included in revenue:				
Pass-through tariff items	(9.6)	(7.1)	(2.5)	(35.2)
Pass-through revenue-sensitive taxes	(95.2)	(86.3)	(8.9)	(10.3)
Net gas revenue for margin	1,085.8	1,010.2	75.6	7.5
Minus purchased gas costs[1]	(762.1)	(723.2)	(38.9)	(5.4)
Gas margin[2]	$ 323.7	$ 287.0	$ 36.7	12.8%

1 *As reported on PSE's Consolidated Statement of Income.*

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

Gas margin increased $36.7 million in 2007 as compared to 2006. Gas margin increased $26.7 million due to a 2.8% general rate increase effective January 13, 2007 which increased gas margin by approximately 9.8% as a result of recovering ownership and operating costs of natural gas plant. In addition, an increase of 3.8% in natural gas therm volume sales increased gas margin $11.0 million. These increases were slightly offset by a change in customer usage and pricing which resulted in a $1.0 million decrease to margin.

Electric Operating Revenues. The table below sets forth changes in electric operating revenues for PSE from 2006 to 2007.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2007	2006	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 951.1	$ 788.2	$ 162.9	20.7%
Commercial sales	748.8	702.8	46.0	6.5
Industrial sales	105.2	103.0	2.2	2.1
Other retail sales, including unbilled revenue	31.7	35.4	(3.7)	(10.5)
Total retail sales	1,836.8	1,629.4	207.4	12.7
Transportation sales	9.4	11.5	(2.1)	(18.3)
Sales to other utilities and marketers	109.7	85.0	24.7	29.1
Other	41.9	51.8	(9.9)	(19.1)
Total electric operating revenues	$ 1,997.8	$ 1,777.7	$ 220.1	12.4%

Electric retail sales increased $207.4 million for 2007 as compared to 2006 due primarily to a decrease in the benefits of the Residential Exchange Benefit credited to residential and small farm customers, which reduced electric operating revenue by $54.9 million in 2007 as compared to $171.3 million in 2006 (an increase in revenue of $116.4 million). The credit also reduced power costs by a corresponding amount with no impact on earnings. The Residential Exchange Benefit was suspended effective June 7, 2007 due to adverse rulings from the Ninth Circuit Court of Appeals (Ninth Circuit) which states that Bonneville Power Administration (BPA) actions in entering into residential exchange settlement agreements with investor owned utilities were not in accordance with the law. The PCORC rate increases of July 1, 2006 and September 1, 2007 offset by the electric general rate decrease of January 13, 2007 increased electric retail sales along with an increase in retail sales volumes. The electric tariff changes increased electric operating revenues by $59.3 million for 2007 as compared to 2006. Retail electricity usage increased 535,301 megawatt hours (MWh) or 2.5% for 2007 as compared to the same period in 2006, which resulted in an increase of approximately $41.2 million in electric operating revenue. The increase in electricity usage was related in part to 2.0% higher average number of customers served in 2007 as compared to 2006. These increases were offset by a decrease in revenue related to production tax credits of $30.8 million given to customers in 2007 as compared to a credit of $13.9 million in 2006.

Transportation sales decreased $2.1 million in 2007 as compared to 2006 as a result of transportation customers balancing their scheduled load. During 2006, transportation customers purchased power in excess of their scheduled load whereas for the same period in 2007, the scheduled load was less than actual usage. This decrease was offset by an increase in sales volume of 39,988 MWh or 1.9%.

Sales to other utilities and marketers increased $24.7 million for 2007 as compared to 2006 due to an increase in sales volume of 185,206 MWh or 9.0%, which resulted in a $9.0 million increase. In 2007, PSE's average wholesale sales price to other utilities and marketers increased $0.0076 as compared to 2006 which resulted in an increase of approximately $15.7 million.

Other electric revenues decreased $9.9 million for 2007 as compared to 2006 primarily due to gains from natural gas financial hedges on natural gas sold to third parties in 2006 that did not recur in 2007.

The following electric rate changes were approved by the Washington Commission in 2007 and 2006:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenues (Dollars in Millions)
Power Cost Only Rate Case	July 1, 2006	5.9 %	$ 45.3 [1]
Electric General Rate Case	January 13, 2007	(1.3)%	(22.8)
Power Cost Only Rate Case	September 1, 2007	3.7 %	64.7

1 *The rate increase is for the period July 1, 2006 through December 31, 2006. The annualized basis of the PCORC rate increase is $96.1 million.*

Gas Operating Revenues. The table below sets forth changes in gas operating revenues for PSE from 2006 to 2007.

(Dollars in Millions) Twelve Months Ended December 31	2007	2006	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 756.2	$ 697.6	$ 58.6	8.4 %
Commercial sales	363.0	335.7	27.3	8.1
Industrial sales	57.7	57.1	0.6	1.1
Total retail sales	1,176.9	1,090.4	86.5	7.9
Transportation sales	13.7	13.3	0.4	3.0
Other	17.4	16.4	1.0	6.1
Total gas operating revenues	$ 1,208.0	$ 1,120.1	$ 87.9	7.8 %

Gas retail sales increased $86.5 million for 2007 as compared to 2006 due to the approval of a 2.8% general natural gas rate increase effective January 13, 2007, higher Purchased Gas Adjustment (PGA) mechanism rates and increased customer natural gas usage. The natural gas general rate increase provided an additional $26.9 million in gas revenues for 2007 as compared to 2006. The approval by the Washington Commission of the PGA mechanism rate increase effective October 1, 2006 increased rates by 10.2% annually and then the approval of a rate decrease effective October 1, 2007 decreased rates 13.0% annually. The PGA mechanism passes through to customers increases or decreases in the natural 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 natural gas pipeline transportation costs. PSE's gas margin and net income are not affected by changes under the PGA mechanism. For 2007, the effects of the PGA mechanism rate changes provided a net increase of $9.7 million in gas operating revenues. The remaining increase in gas retail revenues was primarily due to higher gas sales of 41.6 million therms or $43.3 million for 2007 as compared to 2006, which was related in part to a 2.6% increase in customers.

The following natural gas rate changes were approved by the Washington Commission in 2007 and 2006:

Type of Rate Adjustment	Effective Date	Average Percentage Increase (Decrease) in Rates	Annual Increase (Decrease) in Revenues (Dollars in Millions)
Purchased Gas Adjustment	October 1, 2006	10.2 %	$ 95.1
Gas General Rate Case	January 13, 2007	2.8 %	29.5
Purchased Gas Adjustment	October 1, 2007	(13.0)%	(148.1)

Operating Expenses. The table below sets forth significant changes in operating expenses for PSE from 2006 to 2007.

(Dollars in Millions) Twelve Months Ended December 31	2007	2006	Change	Percent Change
Purchased electricity	$ 895.6	$ 917.8	$ (22.2)	(2.4)%
Electric generation fuel	143.4	97.3	46.1	47.4
Residential exchange	(52.4)	(163.6)	111.2	68.0
Purchased gas	762.1	723.2	38.9	5.4
Unrealized (gain)/loss on derivative instruments	(2.7)	0.1	(2.8)	*
Utility operations and maintenance	403.7	354.6	49.1	13.8
Non-utility expense and other	12.4	4.5	7.9	175.6
Depreciation and amortization	279.2	262.3	16.9	6.4
Conservation amortization	40.0	32.3	7.7	23.8
Taxes other than income taxes	288.5	255.8	32.7	12.8

* *Percent change not applicable or meaningful*

Purchased electricity expenses decreased $22.2 million in 2007 as compared to 2006 due primarily to a decrease in purchased power of 983,297 MWh or 5.5%, resulting in a decrease of $46.6 million, offset by an increase in wholesale market prices which caused an increase of $16.7 million. Contributing to the decrease in purchased power was the increase in electric generation at company-owned facilities. The Power Cost Adjustment (PCA) mechanism reflected a $9.4 million decrease in the deferral of power costs for 2007 as compared to 2006 due to an increase in the overrecovery of allowable power costs shared with customers due to lower power costs in 2007 as compared to 2006. Transmission and other power supply expenses increased by $17.1 million in 2007 as compared to 2006 due in part to increased kilowatt hour (kWh) sales to customers which increased transmission costs.

The July 9, 2007 Columbia Basin Runoff Forecast published by the National Weather Service Northwest River Forecast Center indicated that the total forecasted runoff above Grand Coulee Reservoir for the period April through September 2007 was 99% of normal, which compares to 106% of normal runoff observed for the same period in 2006. The January 2008 Early Bird Columbia Basin Runoff Forecast published by the National Weather Service Northwest River Forecast Center indicated that the total forecasted runoff above Grand Coulee Reservoir for the period January through July 2008 would be 100% 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 increased $46.1 million in 2007 as compared to 2006 primarily due to the addition of the Goldendale generating facility in 2007 which contributed $32.7 million to the cost of fuel and an increase of $8.7 million due to higher volumes of electricity generated at Colstrip which increased coal costs in 2007 as compared to 2006. In addition, higher cost of natural gas fuel at PSE's other combustion turbines contributed $4.7 million in 2007 as compared to 2006.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with the BPA decreased $111.2 million in 2007 as compared to 2006 as a result of lower residential and small farm customer electric credit in rates effective October 1, 2006. The residential exchange credit provided to residential and small farm customers was suspended effective June 7, 2007 due to an adverse ruling from the U.S. Court of Appeals of the Ninth Circuit (Ninth Circuit) which states that BPA actions in entering into residential exchange settlement agreements with investor owned utilities were not in accordance with the law. 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 $38.9 million in 2007 as compared to 2006 primarily due to an increase in PGA rates as approved by the Washington Commission and higher customer therm sales. The PGA mechanism allows PSE to recover expected natural gas costs, and defer, as a receivable or liability, any natural gas costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism payable balance at December 31, 2007 was $77.9 million as compared to a receivable balance at December 31, 2006 of $39.8 million. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable balance in the PGA mechanism reflects an underrecovery of market natural gas cost through rates. A payable balance reflects overrecovery of market natural gas cost through rates.

Unrealized gain on derivative instruments increased $2.8 million in 2007 as compared to 2006 primarily as a result of the unrealized gain related to a physical natural gas supply contract for PSE's electric generating facilities offset by the settlement of a portion of the gain. The mark-to-market gain or loss on the physical natural gas supply contracts is the difference between the forward market price of natural gas and the contract price for natural gas based on volumes purchased. As the contracts near termination, the gain or loss will continue to reverse due to settlement of the contract on a monthly basis and the mark-to-market value will decrease as long as the price for natural gas is at or near the current forward market price.

Utility operations and maintenance expense increased $49.1 million in 2007 as compared to 2006 primarily due to higher operating and maintenance costs of $16.0 million at PSE's generating facilities. The increase in costs at PSE's generating facilities is primarily due to the addition of Wild Horse which began operations on December 22, 2006 and Goldendale, which was acquired during February 2007. Wild Horse operations and maintenance expense is fully recovered in rates and beginning September 1, 2007, Goldendale is fully recovered in rates. Customer service and support services costs increased $19.7 million due to higher costs associated with salaries, benefits, consultants and bad debt reserve. The balance of the increases was the result of infrastructure reliability work performed on the utility's transmission and distribution systems..

Non-utility expense and other increased $7.9 million in 2007 as compared to 2006 primarily due to an increase in PSE's long-term share-based incentive plan costs based on an increase in performance modifiers.

Depreciation and amortization expense increased $16.9 million in 2007 as compared to 2006, which include the benefit of the deferral of Goldendale ownership and operating costs of $10.8 million which, had it not been included, would have resulted in an increase to depreciation and amortization expense of $27.7 million for 2007 as compared to 2006. Also contributing to the increase in depreciation and amortization was $13.5 million from placing Wild Horse into service on December 16, 2006, $2.7 million from placing Goldendale into service on February 22, 2007 and $11.5 million from other depreciable property placed into service in 2007 and 2006. On August 2, 2007, the Washington Commission approved a PCORC settlement agreement filed July 5, 2007 finding the acquisition of Goldendale to be prudent. The Goldendale deferral of ownership and operating costs ceased to be effective September 1, 2007, when PSE was authorized to begin recovering the costs in rates.

Conservation amortization increased $7.7 million in 2007 as compared to 2006 due to higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased $32.7 million in 2007 as compared to 2006 primarily due to a property tax settlement in 2006 with the Washington State Department of Revenue which resulted in lower property valuations in 2006. The increases also reflect an additional plant placed in service as well as revenue sensitive taxes due to increased revenue.

Other Income, Other Expenses, Interest Expense and Income Tax Expense. The table below sets forth significant changes for PSE from 2006 to 2007.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2007	2006	CHANGE	PERCENT CHANGE
Interest expense	$ 206.5	$ 168.9	$ 37.6	22.3 %
Income tax expense	74.2	98.7	(24.5)	(24.8)

Interest expense increased $37.6 million for 2007 as compared to 2006. The increase was driven primarily by additional debt financing in 2007 during which average balances were higher than 2006 levels as a result of financing the Company's construction and plant acquisition projects and higher interest rates. The increase was also driven by more favorable pricing on natural gas purchases in 2007 which resulted in the interest-bearing PGA transferring from a receivable balance in 2006 to a payable balance in 2007.

Income tax expense decreased $24.5 million in 2007 as compared to 2006. The effective tax rate was lower due to higher tax credits associated with the production of wind-powered energy (PTCs). The PTCs for 2007 were $20.2 million as compared to $7.0 million in 2006. These additional credits were made available due to the addition of Wild Horse, which was placed in service in December 2006. In addition, income tax expense benefited from a true-up of the prior year federal income tax provision which resulted in a benefit in 2007 versus an expense in 2006.

2006 COMPARED TO 2005

PUGET SOUND ENERGY

Energy Margins. The following table displays the details of electric margin changes from 2005 to 2006. 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.

	ELECTRIC MARGIN			
(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenue[1]	$ 1,777.7	$ 1,612.9	$ 164.8	10.2 %
Less: Other electric operating revenue	(51.8)	(62.5)	10.7	17.1
Add: Other electric operating revenue – gas supply resale	16.4	26.1	(9.7)	(37.2)
Total electric revenue for margin	1,742.3	1,576.5	165.8	10.5
Adjustments for amounts included in revenue:				
Pass-through tariff items	(35.9)	(26.9)	(9.0)	(33.5)
Pass-through revenue-sensitive taxes	(117.4)	(104.9)	(12.5)	(11.9)
Net electric revenue for margin	1,589.0	1,444.7	144.3	10.0
Minus power costs:				
Purchased electricity[1]	(917.8)	(860.4)	(57.4)	(6.7)
Electric generation fuel[1]	(97.3)	(73.3)	(24.0)	(32.7)
Residential exchange[1]	163.6	180.5	(16.9)	(9.4)
Total electric power costs	(851.5)	(753.2)	(98.3)	(13.1)
Electric margin[2]	$ 737.5	$ 691.5	$ 46.0	6.7 %

1 *As reported on PSE's Consolidated Statement of Income.*

2 *Electric margin does not include any allocation for amortization/depreciation expense or electric generation operation and maintenance expense.*

Electric margin increased $46.0 million in 2006 as compared to 2005 primarily due to the effects of the general rate case rate increase effective March 4, 2005 and the PCORC rate increases effective November 1, 2005 and July 1, 2006 which increased margin by $27.5 million. Retail customer kWh sales (residential, commercial and industrial customers) increased 3.1% in 2006 as compared to 2005, which provided $21.8 million to electric margin. Electric margin also increased by $12.9 million due to overrecovery of excess power cost under the PCA mechanism. Electric margin increased by $1.2 million due to the reduction of the Tenaska disallowance in the PCA mechanism. These increases were partially offset by a $11.2 million decrease related to PTCs provided to customers through tariff rates, which are trued-up to actual PTCs taken in an annual true-up process and the non-recurring benefit of a February 23, 2005 Washington Commission order allowing recovery of power costs that lowered electric margin by $6.0 million.

The following table displays the details of gas margin changes from 2005 to 2006. Gas margin is gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of natural gas purchased, including natural gas transportation costs to bring natural gas to PSE's service territory.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	GAS MARGIN 2006	2005	CHANGE	PERCENT CHANGE
Gas operating revenue[1]	$ 1,120.1	$ 952.5	$ 167.6	17.6%
Less: Other gas operating revenue	(16.5)	(17.2)	0.7	4.1
Total gas revenue for margin	1,103.6	935.3	168.3	18.0
Adjustments for amounts included in revenue:				
Pass-through tariff items	(7.1)	(5.7)	(1.4)	(24.6)
Pass-through revenue-sensitive taxes	(86.3)	(73.1)	(13.2)	(18.1)
Net gas revenue for margin	1,010.2	856.5	153.7	17.9
Minus purchased gas costs[1]	(723.2)	(592.1)	(131.1)	(22.1)
Gas margin[2]	$ 287.0	$ 264.4	$ 22.6	8.5%

1 *As reported on PSE's Consolidated Statement of Income.*

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

Gas margin increased $22.6 million in 2006 as compared to 2005. Gas margin increased $12.6 million due to a 4.7% increase in natural gas therm volume sales; $7.0 million of the increase was a result of the natural gas general tariff rate case which was effective March 4, 2005. These increases were partially offset by a $1.5 million decrease in margin related to customer mix and pricing.

Electric Operating Revenues. The table below sets forth changes in electric operating revenues for PSE from 2005 to 2006.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 788.2	$ 690.2	$ 98.0	14.2%
Commercial sales	702.8	629.0	73.8	11.7
Industrial sales	103.0	93.9	9.1	9.7
Other retail sales, including unbilled revenue	35.4	23.3	12.1	51.9
Total retail sales	1,629.4	1,436.4	193.0	13.4
Transportation sales	11.5	9.0	2.5	27.8
Sales to other utilities and marketers	85.0	105.0	(20.0)	(19.0)
Other	51.8	62.5	(10.7)	(17.1)
Total electric operating revenues	$ 1,777.7	$ 1,612.9	$ 164.8	10.2%

Electric retail sales increased $193.0 million for 2006 as compared to 2005 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 $68.7 million to electric operating revenues for 2006 as compared to 2005. Retail electricity usage increased 626,207 MWh or 3.1% for 2006 as compared to 2005. The increase in electricity usage was mainly the result of a 1.6% higher average number of customers served in 2006 as compared to 2005.

During 2006, the benefits of the Residential and Small Farm Energy Exchange Benefit credited to residential and small farm customers reduced electric operating revenues by $171.3 million as compared to $189.0 million for 2005. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Transportation sales increased $2.5 million for 2006 as compared to 2005 due to an increase in sales volume of 61,524 MWh or 3.0%.

Sales to other utilities and marketers decreased $20.0 million as compared to 2005 due primarily to a decrease in the wholesale market price of electricity in 2006 as compared to 2005 offset by an increase of 180,842 MWh in 2006 from 2005.

Other electric revenues decreased $10.7 million in 2006 as compared to 2005, primarily associated with natural gas purchased for electric generation needs that was subsequently sold rather than used by PSE or gains from electric generation financial derivatives on natural gas sold. The following electric rate changes were approved by the Washington Commission in 2006 and 2005:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Electric General Rate Case	March 4, 2005	4.1 %	$ 57.7
Power Cost Only Rate Case	November 1, 2005	3.7 %	55.6
Power Cost Only Rate Case	July 1, 2006	5.9 %	45.3 [1]

[1] *The rate increase is for the period July 1, 2006 through December 31, 2006. The annualized basis of the PCORC rate increase is $96.1 million.*

Gas Operating Revenues. The table below sets forth changes in gas operating revenues for PSE from 2005 to 2006.

(Dollars in Millions) Twelve Months Ended December 31	2006	2005	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 697.6	$ 592.4	$ 105.2	17.8 %
Commercial sales	335.7	281.3	54.4	19.3
Industrial sales	57.1	48.3	8.8	18.2
Total retail sales	1,090.4	922.0	168.4	18.3
Transportation sales	13.3	13.3	--	0.0
Other	16.4	17.2	(0.8)	(4.7)
Total gas operating revenues	$ 1,120.1	$ 952.5	$ 167.6	17.6 %

Gas retail sales increased $168.4 million for 2006 as compared to 2005 due to higher Purchased Gas Adjustment (PGA) mechanism rates in 2006, approval of a 3.5% gas general rate increase effective March 4, 2005 and higher retail customer natural gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2005 that provided $113.2 million in gas revenues for 2006 as compared to 2005. In addition, the natural gas general rate case increase provided an additional $7.0 million in gas operating revenues for 2006 as compared to in 2005. The remaining increase in gas retail revenues was primarily due to a 3.0% increase in customers and higher natural gas sales of 48.4 million therms or $43.8 million for 2006 as compared to 2005.

The following natural gas rate changes were approved by the Washington Commission in 2006 and 2005:

Type of Rate Adjustment	Effective Date	Average Percentage Increase in Rates	Annual Increase in Revenues (Dollars in Millions)
Gas General Rate Case	March 4, 2005	3.5 %	$ 26.3
Purchased Gas Adjustment	October 1, 2005	14.7 %	121.6
Purchased Gas Adjustment	October 1, 2006	10.2 %	95.1

Operating Expenses. The table below sets forth significant changes in operating expenses for PSE from 2005 to 2006.

(DOLLARS IN MILLIONS) TWELVE MONTHS ENDED DECEMBER 31	2006	2005	CHANGE	PERCENT CHANGE
Purchased electricity	$ 917.8	$ 860.4	$ 57.4	6.7 %
Electric generation fuel	97.3	73.3	24.0	32.7
Residential exchange	(163.6)	(180.5)	16.9	9.4
Purchased gas	723.2	592.1	131.1	22.1
Utility operations and maintenance	354.6	333.3	21.3	6.4
Non-utility expense and other	4.5	7.5	(3.0)	(40.0)
Depreciation and amortization	262.3	241.6	20.7	8.6
Conservation amortization	32.3	24.3	8.0	32.9
Taxes other than income taxes	255.8	233.8	22.0	9.4

Purchased electricity expenses increased $57.4 million in 2006 as compared to 2005 primarily due to a 3.1% increase in retail customer sales volumes and a 9.6% increase in wholesale sales volumes. Total purchased power for 2006 increased 904,560 MWh, or a 5.4% increase over 2005. Increase in the purchased power volumes offset by slightly lower wholesale prices caused an increase of $19.2 million in 2006. The increase in costs also reflected the recovery of previously deferred excess power costs of $12.7 million due to lower power costs in 2006 than the baseline PCA mechanism rate as compared to a deferral of excess power costs of $15.7 million in 2005. Also contributing to the increase in costs was a Washington Commission order that allowed PSE to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003 in 2005. In addition, transmission and other expenses increased $5.0 million due in part to increased kWh sales to customers.

PSE's hydroelectric production and related power costs in 2006 were positively impacted by above-normal precipitation and snow pack in the Pacific Northwest region, which resulted in the runoff above Grand Coulee Reservoir to be 106% of normal as compared to a below normal runoff of 88% in 2005.

Electric generation fuel expense increased $24.0 million in 2006 as compared to 2005 primarily due to an increase of $17.4 million in the cost of fuel at PSE-controlled combustion turbine generating facilities due to higher costs of natural gas offset by slightly lower volumes of electricity generated and an increase in the cost of coal at Colstrip generating facilities of $6.6 million compared to 2005.

Residential exchange credits associated with the Residential Purchase and Sale Agreement with the BPA decreased $16.9 million in 2006 as compared to 2005 as a result of lower residential and small farm customer electric rates. 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. Effective October 1, 2006, the annual payment PSE receives from BPA decreased to $105.5 million for the period through September 30, 2007. This had no impact on PSE's earnings as the payment is passed through to customers through a lower residential exchange tariff credit.

Purchased gas expenses increased $131.1 million in 2006 as compared to 2005 primarily due to an increase in PGA rates as approved by the Washington Commission and higher customer therm sales. The PGA mechanism allows PSE to recover expected natural gas costs, and defer, as a receivable or liability, any natural gas costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism receivable balance at December 31, 2006 and December 31, 2005 was $39.8 million and $67.3 million, respectively. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable balances. A receivable balance in the PGA mechanism reflects a current underrecovery of market natural gas cost through rates. For further discussion on PGA rates see Item 1 – Business - Gas Regulation and Rates.

Utility operations and maintenance expense increased $21.3 million in 2006 as compared to 2005 primarily due to higher production costs of $11.9 million related to major overhauls of Colstrip Units 1 and 4, the Hopkins Ridge wind project which became operational on November 26, 2005, soil remediation costs at PSE's Crystal Mountain electric generation station site and costs to repair a failure of PSE's Whitehorn Unit 2 combustion turbine generator. $7.2 million of the increase was due to higher electric distribution system restoration costs as a result of a series of severe winter storms. In addition, customer service and call center costs increased $3.8 million and gas operations and distribution costs increased $2.0 million. These increases were slightly offset by a decrease of $3.6 million in other expenses. 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.

A series of severe wind storms occurred during 2006 for which PSE incurred significant costs, including a wind storm that occurred in December 2006 that resulted in a loss of electric service to over 700,000 of PSE's customers. PSE incurred over $72.0 million in estimated costs related to this wind storm, the majority of which were deferred in accordance with the Washington Commission's orders. In total, PSE deferred $92.3 million of storm costs in 2006 as a result of a Washington Commission order that allowed deferral of qualified storm costs in excess of $7.0 million. Qualifying storm costs are those that exceed the Institute of Electrical and Electronics Engineers (IEEE) standard for determining system average interruption duration index.

Non-utility operations and maintenance expense decreased $3.0 million in 2006 as compared to 2005 primarily due to expenses for several energy efficiency projects for the United States Navy which were completed in 2005.

Depreciation and amortization expense increased $20.7 million in 2006 as compared to 2005 due primarily to the effects of new generating facilities, electric distribution system plant and natural gas distribution system plant placed in service, of which $8.1 million is from placing the Hopkins Ridge wind project in service on November 26, 2005.

Conservation amortization increased $8.0 million in 2006 as compared to 2005 due to higher authorized recovery of electric and natural gas conservation expenditures. Conservation amortization is a pass-through tariff item with no impact on earnings.

Taxes other than income taxes increased $22.0 million in 2006 as compared to 2005 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. Excluding the impact of revenue sensitive taxes, taxes other than income taxes decreased $3.8 million primarily as a result of a 2006 property tax reduction settled with the Washington State Department of Revenue in August 2006 which resulted in a lower valuation for tax purposes in 2006 as compared to 2005.

Other Income, Other Expenses, Interest Expense and Income Tax Expense. The table below sets forth significant changes in other income and interest charges for PSE from 2005 to 2006.

(Dollars in Millions) Twelve Months Ended December 31	2006	2005	Change	Percent Change
Other income	$ 28.2	$ 12.0	$ 16.2	135.0 %
Other expenses	6.6	4.8	1.8	37.5
Interest expense	169.0	165.0	4.0	2.5
Income taxes	98.7	87.1	11.6	13.3

Other income increased $16.2 million in 2006 as compared to 2005 primarily due to an increase in the accrual of carrying costs on regulatory assets of $12.2 million and an increase of $4.2 million in the equity portion of allowance for funds used during construction (AFUDC).

Other expenses increased by $1.8 million due to regulatory penalties incurred in 2006.

Interest expense increased $4.0 million in 2006 as compared to 2005 due primarily to interest expense of $6.4 million related to an increase in debt due to construction projects offset by an increase in the debt AFUDC credit.

Income taxes increased $11.6 million in 2006 as compared to 2005 due to higher taxable income slightly offset by a lower effective tax rate influenced by PTCs.

INFRASTRUX

On May 7, 2006, Puget Energy sold its 90.9% interest in InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska), resulting in after-tax cash proceeds of approximately $95.9 million, an after-tax gain of $29.8 million for 2006. Puget Energy accounted for InfrastruX as a discontinued operation under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) in 2005 and 2006.

Under the terms of the sale agreement, Puget Energy remains obligated for certain representations and warranties made by InfrastruX concerning its business through May 7, 2008. Puget Energy obtained a representation and warranty insurance policy and deposited $3.7 million into an escrow account as retention under the policy. As of December 31, 2006, long-term restricted cash in the amount of $3.8 million was included in the accompanying balance sheets and represented Puget Energy's maximum exposure related to those commitments. At December 31, 2007, the amount was $4.0 million. Puget

Energy also agreed to indemnify the purchaser for certain potential future losses related to one of InfrastruX's subsidiaries through May 7, 2011, with the maximum amount of loss not to exceed $15.0 million. A liability in the amount of $5.0 million was included in the accompanying balance sheets as of December 31, 2006, which represents Puget Energy's estimate of the fair value of the amount potentially payable using a probability-weighted approach to a range of future cash flows. At December 31, 2007, the amount was $3.2 million. Puget Energy also provided an environmental guarantee as part of the sale agreement. Puget Energy believes it will not have a future loss in connection with the environmental guarantee.

For 2006, Puget Energy reported InfrastruX related income from discontinued operations, including gain on sale, of $51.9 million compared to $9.5 million for 2005 (in each case, net of taxes and minority interest). Puget Energy's income from discontinued operations for 2006 includes $7.3 million related to the reversal of a carrying value adjustment recorded in 2005 as well as $10.0 million related to the anticipated realization of a deferred tax asset associated with the sale of the business.

InfrastruX's operating revenue through May 7, 2006 was $138.6 million compared to $393.3 million for the twelve months ended December 31, 2005. Pre-tax income for the twelve months ended December 31, 2006 was $9.9 million compared to $36.4 million for the same period in 2005.

CAPITAL RESOURCES AND LIQUIDITY

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

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

Puget Energy		PAYMENTS DUE PER PERIOD			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2008	2009-2010	2011-2012	2013 & Thereafter
Long-term debt including interest	$ 6,435.2	$ 361.3	$ 712.8	$ 520.9	$ 4,840.2
Short-term debt including interest	260.5	260.5	--	--	--
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	412.5	65.2	125.8	90.8	130.7
Non-cancelable operating leases	170.8	16.5	50.8	25.7	77.8
Fredonia combustion turbines lease [1]	50.9	3.9	7.7	39.3	--
Energy purchase obligations	6,298.9	1,095.6	1,751.8	953.7	2,497.8
Contract initiation payment/collateral requirement	18.5	--	--	18.5	--
Financial hedge obligations	(5.9)	(2.5)	(3.4)	--	--
Purchase obligations	66.7	27.9	22.7	--	16.1
Non-qualified pension and other benefits funding and payments	41.6	5.8	8.1	8.0	19.7
Other obligations	7.7	7.7	--	--	--
Total contractual cash obligations	$ 13,759.3	$ 1,841.9	$ 2,676.3	$ 1,656.9	$ 7,584.2

Puget Energy		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2008	2009-2010	2011-2012	2013 & THEREAFTER
Indemnity agreements [2]	$ 7.2	$ 4.0	$ --	$ 3.2	$ --
Credit agreement - available [3]	734.1	--	--	--	734.1
Receivables securitization facility [4]	48.0	--	--	48.0	--
Energy operations letter of credit	7.4	7.4	--	--	--
Total commercial commitments	$ 796.7	$ 11.4	$ --	$ 51.2	$ 734.1

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

2 *Under the InfrastruX sale agreement, Puget Energy is obligated for certain representations and warranties concerning InfrastruX's business and anti-trust inquiries. The fair value of the business warranty was $4.0 million at December 31, 2007 and the obligation expires on May 7, 2008. Puget Energy also agreed to indemnify the buyer relating to an inquiry of an InfrastruX subsidiary and the fair value of the warranty was $3.2 million at December 31, 2007. See "InfrastruX" above for further discussion.*

3 *At December 31, 2007, PSE had available a $500.0 million and a $350.0 million unsecured credit agreement, each expiring in April 2012. The credit agreement provides credit support for letters of credit and commercial paper. At December 31, 2007, PSE had $7.4 million outstanding under four letters of credit, and $108.5 million commercial paper outstanding, effectively reducing the available borrowing capacity to $734.1 million.*

4 *At December 31, 2007, PSE had available a $200.0 million receivables securitization facility that expires in December 2010. $152.0 million was outstanding under the receivables securitization facility at December 31, 2007 thus leaving $48.0 million available. The facility allows receivables to be used as collateral to secure short-term loans, not exceeding the lesser of $200.0 million or the borrowing base of eligible receivables, which fluctuate with the seasonality of energy sales to customers. See "Receivables Securitization Facility" below for further discussion.*

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

Puget Sound Energy CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	Total	2008	2009-2010	2011-2012	2013 & Thereafter
		PAYMENTS DUE PER PERIOD			
Long-term debt including interest	$ 6,435.2	$ 361.3	$ 712.8	$ 520.9	$ 4,840.2
Short-term debt including interest	276.3	276.3	--	--	--
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	412.5	65.2	125.8	90.8	130.7
Non-cancelable operating leases	170.8	16.5	50.8	25.7	77.8
Fredonia combustion turbines lease [1]	50.9	3.9	7.7	39.3	--
Energy purchase obligations	6,298.9	1,095.6	1,751.8	953.7	2,497.8
Contract initiation payment/collateral requirement	18.5	--	--	18.5	--
Financial hedge obligations	(5.9)	(2.5)	(3.4)	--	--
Purchase obligations	66.7	27.9	22.7	--	16.1
Non-qualified pension and other benefits funding and payments	41.6	5.8	8.1	8.0	19.7
Other obligations	7.7	7.7	--	--	--
Total contractual cash obligations	$ 13,775.1	$ 1,857.7	$ 2,676.3	$ 1,656.9	$ 7,584.2

Puget Sound Energy. The following are PSE's aggregate commercial commitments as of December 31, 2007:

Puget Sound Energy COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	Total	2008	2009-2010	2011-2012	2013 & Thereafter
		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
Credit agreement - available [2]	$ 734.1	$ --	$ --	$ --	$ 734.1
Receivables securitization facility [3]	48.0	--	--	48.0	--
Energy operations letter of credit	7.4	7.4	--	--	--
Total commercial commitments	$ 789.5	$ 7.4	$ --	$ 48.0	$ 734.1

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

OFF-BALANCE SHEET ARRANGEMENTS

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, 2007, PSE's outstanding balance under the lease was $48.3 million. The expected residual value under the lease is the lesser of $37.4 million or 60.0% 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

PSE's construction programs for generating facilities, the electric transmission system and the natural gas and electric distribution system are designed to meet continuing customer growth and to support reliable energy delivery. The cash flow construction expenditures, excluding equity AFUDC and customer refundable contributions was $720.4 million in 2007. The anticipated utility construction expenditures, excluding AFUDC, for 2008, 2009 and 2010 are:

CAPITAL EXPENDITURE PROJECTIONS (DOLLARS IN MILLIONS)	2008	2009	2010
Energy delivery, technology and facilities	$ 595.0	$ 568.0	$ 743.0
New resources	72.0	220.0	514.0
Total expenditures	$ 667.0	$ 788.0	$ 1,257.0

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.

CAPITAL RESOURCES

CASH FROM OPERATIONS

Cash generated from operations for 2007 was $564.0 million, which is 72.2% of the $780.7 million used for utility construction expenditures and other capital expenditures. For 2006, cash generated from operations was $185.5 million which is 23.7% of the $783.4 million used for utility construction expenditures and other capital expenditures.

The overall cash generated from operating activities for 2007 increased $378.5 million as compared to 2006. The increase was primarily the result of $102.2 million less income tax paid in 2007, the collection of the purchased gas receivable of $90.2 million in 2007, the increase in the collection of $73.5 million in accounts receivable, a cash receipt of $18.9 million from the lease purchase option settlement for the Bellevue offices and $63.1 million less cash paid for storm damage costs. In addition, there were costs incurred in 2006 which did not recur in 2007, including the Chelan PUD contract initiation payment of $89.0 million, cash collateral re-payment to energy suppliers for $22.0 million and proceeds from the sale of InfrastruX of $29.8 million. The increase in cash generated from operating activities for 2007 was partially offset by a decrease of $88.7 million in payments made for accounts payable related to energy purchases and a $22.5 million increase in payments to customers related to the Residential Exchange program.

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 depends 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 natural gas mortgage indentures, restated articles of incorporation and certain loan agreements. Under the most restrictive tests, at December 31, 2007, PSE could issue:

- approximately $592.0 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $986.7 million of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest (as defined in the electric utility mortgage), which PSE exceeded at December 31, 2007;
- approximately $507.0 million of additional first mortgage bonds under PSE's natural gas mortgage indenture based on approximately $845.0 million of natural gas bondable property available for issuance, subject to interest coverage ratio limitations of 1.75 times and 2.0 times net earnings available for interest (as defined in the gas utility mortgage), which PSE exceeded at December 31, 2007;
- approximately $1.0 billion of additional preferred stock at an assumed dividend rate of 7.8%; and
- approximately $763.5 million of unsecured long-term debt.

At December 31, 2007, PSE had approximately $4.5 billion in electric and natural 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 natural 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 20, 2008, were:

	Ratings	
	Standard & Poor's	Moody's
Puget Sound Energy		
Corporate credit/issuer rating	BBB-	Baa3
Senior secured debt	BBB+	Baa2
Junior subordinated notes	BB	Ba1
Preferred stock	BB	Ba2
Commercial paper	A-3	P-2
Revolving credit facility	Note 1	Baa3
Ratings outlook	Note 2	Note 3
Puget Energy		
Corporate credit/issuer rating	BBB-	Ba1
Ratings Outlook	Note 2	Note 3

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

2 *On October 26, 2007, Standard& Poor's placed the ratings of Puget Energy (BBB-) and PSE (BBB-/A-3) on CreditWatch with negative implications. The CreditWatch listing reflects the possibility that debt ratings for Puget Energy could be lowered dependent on the final outcome of regulatory approval proceedings.*

3 *On October 29, 2007, Moody's placed the Ba1 Issuer rating of Puget Energy on review for possible downgrade. Moody's also affirmed the long-term ratings of PSE and changed its rating outlook to stable from positive. On this same date, Moody's placed PSE's P-2 short-term rating for commercial paper under review for possible downgrade.*

SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

On March 16, 2006, Puget Energy and PSE filed a shelf registration statement with the Securities and Exchange Commission for the offering of:

- common stock of Puget Energy;
- senior notes of PSE, secured by first mortgage bonds;
- preferred stock of PSE; and
- trust preferred securities of Puget Sound Energy Capital Trust III.

The registration statement is valid for three years and does not specify the amount of securities that the Company may offer. The Company is subject to restrictions under PSE's indentures and articles of incorporation on the amount of first mortgage bonds, unsecured debt and preferred stock that the Company may issue.

On June 1, 2007, PSE redeemed the remaining 8.231% Capital Trust Preferred Securities (classified on the balance sheet as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities and referred to herein as "Securities"). The purpose of the redemption was to help reduce interest costs by retiring higher cost debt. The remaining $37.8 million of the Securities outstanding were redeemed on June 1, 2007 at a 4.12% premium, or $39.3 million, plus accrued interest on the redemption date.

On June 4, 2007, PSE issued $250.0 million of Junior Subordinated Notes (Notes) due June 2067. The Notes bear a fixed rate of interest of 6.974% for the first ten and a half years with interest payable semiannually in May and November of each year, after which the notes will bear a variable rate of interest (3-month LIBOR plus 2.35%). Proceeds were used to fund the redemption of the remaining $37.8 million 8.231% Securities and to repay short-term debt. The Notes are structured to be treated as debt by the Internal Revenue Service (IRS), yet they are considered to contain equity-like characteristics by the credit rating agencies. In addition, the Notes contain a call option feature and are callable in whole or in part by PSE on or after June 1, 2017. They are presented on the balance sheet as a separate line item in the redeemable securities and long-term debt.

Puget Energy completed the sale of 12.5 million shares of common stock pursuant to the stock purchase agreement the Company announced on October 25, 2007, among Puget Energy and a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners (collectively the Purchasers). The Purchasers paid an aggregate offering price of $295.9 million. The securities were sold in a private placement, without registration under the Securities Act of 1933. Puget Energy intends to use the net proceeds from the issuance to invest in PSE for capital expenditures, debt redemption and working capital.

Based on PSE's goal to become energy self-sufficient, it is expected that further issuances of debt, equity or a combination of the two will be necessary in the future. The structure, timing and amount of such financings depend on market conditions and financing needed.

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 was not significantly impacted by the current credit environment.

PSE CREDIT FACILITIES

The Company has three committed credit facilities that provide, in aggregate, $1.05 billion in short-term borrowing capability. These include a $500.0 million credit agreement, a $200.0 million accounts receivable securitization facility and a $350.0 million credit agreement to support hedging activity.

Credit Agreements. In March 2007, PSE entered into a five-year, $350.0 million credit agreement with a group of banks. The agreement is used to support the Company's energy hedging activities and may also be used to provide letters of credit. The interest rate on outstanding borrowings is based either on the agent bank's prime rate or on LIBOR plus a marginal rate related to 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 related to long-term credit ratings of PSE. At December 31, 2007, there were no borrowings or letters of credit outstanding under the credit facility.

In March 2005, PSE entered into a five-year $500.0 million unsecured credit agreement with a group of banks. In March 2007, PSE restated this credit agreement to extend the expiration date to April 2012. The agreement is primarily used to provide credit support for commercial paper and letters of credit. The terms of this agreement, as restated, are essentially identical to those contained in the $350.0 million facility described above.

At December 31, 2007, there was $7.4 million outstanding under four letters of credit and $108.5 million commercial paper outstanding, effectively reducing the available borrowing capacity under the two credit agreements to $734.1 million.

Receivables Securitization Facility. PSE entered into a five-year Receivables Sales Agreement with PSE Funding, Inc. (PSE Funding), a wholly owned subsidiary, 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 $200.0 million or the borrowing base of eligible receivables which fluctuate with the seasonality of energy sales to customers. All loans from this facility will be reported as short-term debt in the financial statements. The PSE Funding facility expires in December 2010, and is terminable by PSE and PSE Funding upon notice to the banks. There were $152.0 million in loans that were secured by accounts receivable pledged at December 31, 2007. The remaining borrowing base of eligible receivable at December 31, 2007 was $48.0 million.

Demand Promissory Note. On June 1, 2006, PSE entered into a revolving credit facility with its parent, Puget Energy, in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of (a) PSE's outstanding commercial paper interest rate; (b) PSE's senior unsecured revolving credit facility; or (c) the interest rate available under the receivables securitization facility of PSE Funding, a PSE subsidiary, which is the LIBOR rate plus a marginal rate. At December 31, 2007, the outstanding balance of the Note was $15.8 million. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements.

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 $9.8 million (399,993 shares) in 2007 as compared to $13.5 million (615,648 shares) in 2006. The proceeds from sales of stock under the Stock Purchase and Dividend Reinvestment Plan are used for general corporate needs. Pending the outcome of the merger, Puget Energy does not intend to fund the Stock Purchase and Dividend Reinvestment Plan with authorized but unissued shares.

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 (NYSE) at market prices.

OTHER

IRS Audit. As a matter of course, the Company's tax returns are routinely audited by federal, state and city tax authorities. In May 2006, the IRS completed its examination of the company's 2001, 2002 and 2003 federal income tax returns. The Company formally appealed the IRS audit adjustment relating to the Company's accounting method with respect to capitalized internal labor and overheads. In its 2001 tax return, PSE claimed a deduction when it changed its tax accounting method with respect to capitalized internal labor and overheads. Under the new method, the Company could immediately deduct certain costs that it had previously capitalized. In the audit, the IRS disallowed the deduction.

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 did not impact earnings but did have a cash flow impact of $33.2 million in the fourth quarter 2005 and $33.1 million in 2006. As of December 31, 2006, the full tax benefit had been repaid.

During 2007, the IRS national office established settlement guidelines which the appeals office will use in reaching settlements with taxpayers. The effect of the settlement guidelines shift some of the benefits claimed in 2001 through 2004 into 2005 and 2006. As a result, the Company has accrued interest in the amount of $5.5 million.

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 Washington Commission had reduced PSE's ratebase by $72.0 million in its order of February 18, 2005. The accounting petition was approved by the Washington 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. The Washington Commission granted cost recovery of these deferred carrying costs over two years, beginning January 13, 2007.

In its 2003 tax return, the Company claimed a deduction for a portion of the California Independent System Operator (CAISO) receivable. Upon examination, the IRS claimed that the deduction was not valid for the 2003 tax year. The Company formally appealed. In appeals, the Company and the IRS agreed to move the deduction from 2003 to 2005. In the fourth quarter 2007, the Company recorded interest expense in the amount of $2.2 million to reflect the transfer of the deduction from 2003 to 2005. In addition, it is management's expectation that the Company could request rate recovery of the regulatory asset for the interest accrued.

Tenaska Disallowance. The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage natural 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 $7.8 million, $9.0 million and $4.1 million in 2007, 2006 and 2005, 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 confirmed that if the Tenaska natural gas costs are deemed prudent, PSE will recover the full amount of actual natural gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded. Due to fluctuations in forward market prices of natural 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, 2007 based on current forward market natural gas prices are as follows:

(DOLLARS IN MILLIONS)	2008	2009	2010	2011
Projected Tenaska costs *	$ 241.6	$ 262.7	$ 260.4	$ 240.7
Projected Tenaska benchmark costs	182.9	189.9	197.4	205.5
Over benchmark costs	$ 58.7	$ 72.8	$ 63.0	$ 35.2
Projected 50% disallowance based on Washington Commission methodology	$ 6.4	$ 4.9	$ 3.1	$ 1.1

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

Regulatory Matters. On December 15, 2006, FERC began an audit of PSE's Open Access Transmission Tariff and Standards of Conduct for the period January 1, 2004 through December 31, 2006. The focus of the audit is PSE's operation of its electric transmission system and tariff and its energy trading function. The audit is on-going and as of February 28, 2008, an audit report has not been issued. PSE expects a draft audit report to be issued for PSE review in the first quarter 2008 with a final report shortly thereafter. The FERC audit team has identified several areas of concern, but at this point PSE is not aware which of these issues, if any, will be included in the final audit report. While FERC has authority to assess regulatory penalties for non-compliance with their regulatory policies, PSE is not able to predict the outcome of the audit at this time.

In November 2007, PSE was audited by the Western Electricity Coordinating Council (WECC) under delegated authority of the NERC, the FERC-certified Electric Reliability Organization (ERO). Previously PSE had submitted several self reports and mitigation plans to WECC for review and approval. The WECC audit team told PSE of four additional preliminary alleged violations (without any specified penalties) that were not previously self reported. In response, PSE submitted self reports and mitigation plans for the four violations. WECC has accepted the self reports and mitigation plans. The ultimate result of the audit, including the nature or amount of any penalties, cannot be predicted at this time.

On December 18, 2007, PSE received a data request from the Investigations Division of the Office of Enforcement at FERC seeking information about certain natural gas pipeline capacity release transactions PSE entered into in 2006 and 2005. PSE responded to the data requests on January 23, 2008 and met with FERC staff on January 31, 2008. At this meeting, PSE discussed with FERC staff additional transactions discovered in the course of responding to the data requests that potentially may be in violation of FERC regulations. PSE received additional data requests from FERC on February 20, 2008. PSE is not able to predict the outcome of this investigation at this time.

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

The following discussion summarizes the status as of the date of this report of ongoing proceedings relating to the western power markets to which PSE is a party. PSE is vigorously defending each of these cases. 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.

California Receivable and California Refund Proceeding. Since 2001, PSE has held a receivable relating to unpaid bills for power that PSE sold in 2000 into the markets maintained by the CAISO. At December 31, 2007, the net receivable for such sales was approximately $21.1 million. PSE's ability to recover all or a portion of this amount is uncertain. At this time, management believes there is no reasonable basis under applicable financial accounting standards to adjust PSE's net receivable because the outcome of further court and FERC actions is uncertain and any likely financial impact cannot be quantified.

In 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). FERC also ordered that if the refunds required by the formula it adopted would cause a seller to recover less than its actual costs for the refund period, the seller is allowed to document its costs and limit its refund liability commensurately. Consistent with those orders, PSE filed a fuel cost adjustment claim and a portfolio cost claim. Recovery of those amounts is uncertain, but the amount owed to PSE under all FERC orders to date is included in the PSE net receivable amount. FERC has not issued a final order determining "who owes how much to whom" in the California Refund Proceeding and it is not clear when such an order will be issued.

In the course of the California Refund Proceeding, FERC has issued dozens of orders. Most have been taken up on appeal before the Ninth Circuit, which has issued opinions on some issues in the last several years. These cases are described below in the section, "California Litigation."

California Litigation. *Lockyer v. FERC.* 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. This case was originally presented to FERC upon complaint that the adoption and implementation of market rate authority was flawed. FERC dismissed the complaint after all sellers refiled summaries of transactions with California entities during 2000 and 2001. 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 remands to FERC the question of whether to allow refunds. On December 28, 2006, PSE and several other energy sellers filed a petition for a writ of certiorari to the U.S. Supreme Court, but the petition was not granted and the matter was remanded to FERC for further proceedings on December 4, 2007. 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.

CPUC v. FERC. On August 2, 2006, the Ninth Circuit decided that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000 and additionally ruled that FERC should consider remedies for transactions previously considered outside the scope of the proceedings. The August 2, 2006 decision may adversely impact PSE's ability to recover the full amount of its CAISO receivable. The decision may also expose PSE to claims or liabilities for transactions outside the previously defined "refund period." At this time the ultimate financial outcome for PSE is unclear. Rehearing by the Ninth Circuit on this matter was sought on November 16, 2007. The rehearing petition has not been acted upon. In addition, parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on PSE.

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 investigated 26 entities that allegedly had potential "partnerships" with Enron. PSE was not named in that show cause order. On January 22, 2004, FERC stated that it did not intend to proceed further against other parties.

The second show cause order 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 a nominal amount to settle all claims. FERC approved the settlement on January 22, 2004. The California parties filed for rehearing of that order. On March 17, 2004, PSE moved to dismiss the California parties' rehearing request and awaits FERC action on that motion.

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 ordered for the California markets. FERC dismissed PSE's complaint, but PSE challenged that dismissal. On June 19, 2001, FERC ordered price caps on energy sales throughout the West. Various parties, including the Port of Seattle and the cities of Seattle and Tacoma, then moved to intervene in the proceeding seeking retroactive refunds for numerous transactions. The proceeding became known as the "Pacific Northwest Refund Proceeding," though refund claims were outside the scope of the original complaint. On June 25, 2003, FERC terminated the proceeding on procedural, jurisdictional and equitable grounds and on November 10, 2003, FERC on rehearing, confirmed the order terminating the proceeding. On August 24, 2007, the Ninth Circuit issued a decision concluding that FERC should have evaluated and considered evidence of market manipulation in California and its potential impact in the Pacific Northwest. It also decided that FERC should have considered purchases made by the California Energy Resources Scheduler and/or the California Department of Water Resources in the Pacific Northwest Proceeding. On December 17, 2007, PSE and Powerex separately filed requests for rehearing with the Ninth Circuit of this decision. Those requests remain pending. PSE intends to vigorously defend its position in this proceeding, but it is unable to predict the outcome of this matter.

Wah Chang Suit. In June 2004, Wah Chang, an Oregon company, filed suit in federal court against Puget Energy and PSE, among others. The complaint is similar to the allegations made in other cases that were dismissed as having no merit. The case was 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 Ninth Circuit. Oral argument took place on April 10, 2007 and the Ninth Circuit issued an opinion affirming the lower court's dismissal of the case on November 20, 2007. Wah Chang filed a petition for rehearing; on January 15, 2008, the Ninth Circuit denied rehearing.

PROCEEDING RELATING TO THE PROPOSED MERGER

On October 26, 2007 and November 2, 2007, two separate lawsuits were filed against the Company and all of the members of the Company's Board of Directors in Superior Court in King County, Washington. The lawsuits, respectively, are entitled, *Tansey v. Puget Energy, Inc., et al.*, Case No. 07-2-34315-6 SEA and *Alaska Ironworkers Pension Trust v. Puget Energy, Inc., et al.,* Case No. 07-2-35346-1 SEA. The lawsuits are both denominated as class actions purportedly on behalf of Puget Energy's shareholders and assert substantially similar allegations and causes of action relating to the proposed merger. (See Note 24 for more information regarding the proposed transaction.) The complaints allege that the Company's directors breached their fiduciary duties in connection with the merger and seek virtually identical relief, including an order enjoining the consummation of the merger. Pursuant to a court order dated November 26, 2007, the two cases were consolidated for all purposes and entitled *In re Puget Energy, Inc. Shareholder Litigation*, Case No. 07-2-34315-6 SEA.

On February 7, 2008, the parties entered into a memorandum of understanding providing for the settlement of the consolidated lawsuit, subject to customary conditions including completion of appropriate settlement documentation, confirmatory discovery and court approval. Pursuant to the memorandum of understanding, the Company has agreed to include certain additional disclosures in its proxy statement relating to the merger. The Company does not admit, however, that its prior disclosures were in any way materially misleading or inadequate. In addition, the Company and the other defendants in the consolidated lawsuit deny the plaintiffs' allegations of wrongdoing and violation of law in connection with the merger. The settlement, if completed and approved by the court, will result in dismissal with prejudice and release of all claims of the plaintiffs and settlement class of the Company's shareholders that were or could have been brought on behalf of the plaintiffs and the settlement class. In connection with such settlement, the plaintiffs intend to seek a court-approved award of attorneys' fees and expenses in an amount up to $290,000, which the Company has agreed to pay.

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 natural 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 require the use of estimates and assumptions that affect the reported amounts of revenue.

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" (SFAS No. 71). 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, 2007 in the amount of $794.2 million and $288.3 million, respectively, and regulatory assets and liabilities of $838.5 million and $191.6 million, respectively, at December 31, 2006. 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 that vary from baseline rates over a graduated scale. 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" (SFAS No. 133), 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 natural gas portfolios, Puget Energy enters into contracts to purchase or sell electricity and natural gas. These contracts are considered derivatives under SFAS No. 133 unless a determination is made that they qualify for the 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 purchase and normal sale 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 and 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. The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open natural gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 100 scenarios of how the Company's natural gas and power portfolios will perform under various weather, hydro and unit performance conditions.

Pension and Other Postretirement Benefits. Puget Energy has a qualified defined benefit pension plan covering substantially all employees of PSE. Qualified pension expense of $2.8 million and $1.0 million was recorded in 2007 and 2006, respectively, and income of $2.6 million was recorded in the financial statements for 2005. Of these amounts, approximately 58.6%, 56.6% and 63.0% offset utility operations and maintenance expense in 2007, 2006 and 2005, respectively, and the remaining amounts were capitalized. It is expected that PSE will recognize qualified pension income of $3.0 million in 2008.

PSE's pension and other postretirement benefits income or costs depend on several factors and assumptions, including plan design, 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. The Company's accounting policy for calculating the market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year. During 2007, PSE made no cash contributions to the qualified defined benefit plan and expects to make no contributions in 2008.

The following 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):

	Change in Assumption	Impact on Projected Benefit Obligation (Increase) Decrease		Impact on 2007 Pension Expense (Increase) Decrease	
(Dollars in Thousands)		Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Increase in discount rate	50 basis points	$ (21,207)	$ (2,485)	$ (2,196)	$ (251)
Decrease in discount rate	50 basis points	23,230	2,691	2,384	270
Increase in return on plan assets	50 basis points	*	*	(2,355)	(75)
Decrease in return on plan assets	50 basis points	*	*	2,355	75

* *Calculation not applicable.*

California Receivable. 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, 2007, such remaining receivables were approximately $21.1 million.

Based on the calculation of existing FERC orders issued to date, PSE has determined that the receivable balance at December 31, 2007 is collectible from the CAISO. However, PSE's ability to collect all or a portion of this amount may be impaired by future FERC orders or decisions by the Ninth Circuit.

Stock Compensation. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R (revised 2004), "Share-Based Payment" (SFAS No. 123R), using the modified-prospective transition method. Results for prior periods have not been restated, as provided for under the modified-prospective method. Prior to 2006, stock-based compensation plans were accounted for according to Accounting Principles Board (APB) No. 25, "Accounting for Stock Issued to Employees" (APB No. 25), and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). 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" (SFAS No. 148). The Company applied SFAS No. 123 accounting to stock compensation awards granted subsequent to January 1, 2003, while grants prior to 2003 continued to be accounted for using the intrinsic value method of APB No. 25.

The adoption of SFAS 123R resulted in a cumulative benefit from an accounting change of $0.1 million, after tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense for unvested awards. As a result of adopting SFAS No. 123R on January 1, 2006, the Company's income before income taxes and net income from continuing operations for the twelve months ended December 31, 2006 was $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123 due to the inclusion of estimated forfeitures in compensation cost.

The fair value of the stock-based grants is based on the closing price of the Company's common stock on the date of measurement and historical performance of the certain share grants and prospective analysis using the Capital Asset Pricing Model and expected EPS growth rates. Based on this analysis, the Company's total shareholder returns would need to significantly increase as compared to other companies to have a material impact on the Company's financial statements. Shares granted prior to 2006 were valued using the Black-Scholes option pricing model.

NEW ACCOUNTING PRONOUNCEMENTS

On September 15, 2006, FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which clarifies how companies should use fair value measurements in accordance with GAAP for recognition and disclosure. SFAS No. 157 establishes a common definition of fair value and a framework for measuring fair value under GAAP, along with expanding disclosures about fair value measurements to eliminate differences in current practice that exist in measuring fair value under the existing accounting standards. The definition of fair value in SFAS No. 157 retains the notion of exchange price; however, it focuses on the price that would be received to sell the asset or paid to transfer the liability (i.e., an exit price), rather than the price that would be paid to acquire the asset or received to assume the liability (i.e., an entry price). Under SFAS No. 157, a fair value measure should reflect all of the assumptions that market participants would use in pricing the asset or liability, including assumptions about the risk inherent in a particular valuation technique, the effect of a restriction on the sale or use of an asset, and the risk of nonperformance. To increase consistency and comparability in fair value measures, SFAS No. 157 establishes a three-level fair value hierarchy to prioritize the inputs used in valuation techniques between observable inputs that reflect quoted prices in active markets, inputs other than quoted prices with observable market data and unobservable data (e.g., a company's own data). SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which is the year beginning January 1, 2008, for the Company. On February 6, 2008, the FASB decided to issue a final FASB Staff Position (FSP) that would partially defer the effective date of SFAS No. 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value, except for those that are recognized or disclosed at fair value on an annual or more frequent basis. The Company adopted SFAS No. 157 on January 1, 2008, prospectively, as required by the Statement, with certain exceptions, including the following noted in paragraph 37 (a) of the statement, "A financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in footnote 3 of Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3), prior to the initial adoption of this Statement." At the date this Statement is initially applied to the financial statements, a difference between the carrying amounts and the fair values of those instruments shall be recognized as a cumulative-effect adjustment to the opening balance of retained earnings.

The Company estimates that the impact of the adoption of SFAS No. 157 to its statement of financial position and results of operations to be a cumulative effect adjustment to retained earnings of $9.0 million before tax as a result of recording a deferred loss on net derivative assets and liabilities.

In July 2006, Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." FIN 48 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. As of the date of adoption, the Company had no material unrecognized tax benefits. As of December 31, 2007, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ENERGY PORTFOLIO MANAGEMENT

The Company has energy risk policies and procedures to manage commodity and volatility risks. The Company's Energy Management Committee establishes the Company's energy risk management policies and procedures, and monitors compliance. The Energy Management Committee is comprised of certain Company officers and is overseen by the Audit Committee of the Company's Board of Directors.

The Company is focused on commodity price exposure and risks associated with volumetric variability in the natural gas and electric portfolios. It is not engaged in the business of assuming risk for the purpose of speculative trading. The Company hedges open natural gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 100 scenarios of how the Company's natural gas and power portfolios will perform under various weather, hydro and unit performance conditions. The objectives of the hedging strategy are to:

- ensure physical energy supplies are available to reliably and cost-effectively serve retail load;
- manage energy portfolio risks prudently to serve retail load at overall least cost and limit undesired impacts on PSE's customers and shareholders; and
- reduce power costs by extracting the value of the Company's assets.

The following table presents electric derivatives that are designated as cash flow hedges or contracts that do not meet Normal Purchase Normal Sale (NPNS) at December 31, 2007 and December 31, 2006:

	Electric Derivatives	
(Dollars in Millions)	December 31, 2007	December 31, 2006
Short-term asset	$ 11.1	$ 10.1
Long-term asset	6.6	6.8
Total assets	$ 17.7	$ 16.9
Short-term liability	$ 9.8	$ 9.0
Long-term liability	--	0.4
Total liabilities	$ 9.8	$ 9.4

If it is determined that it is uneconomical to operate PSE's controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in the unrealized gains and losses associated with the contracts being recorded in the income statement. As these contracts are settled, the costs are recognized as energy costs and are included as part of the PCA mechanism.

At December 31, 2007, the Company had an unrealized day one loss deferral of $9.0 million related to a three year locational power exchange contract which was modeled and therefore the day one loss was deferred under EITF No. 02-3. The deferred loss is being amortized over the term of the contracts. Any future changes in the mark-to-market value will be recorded through the income statement. The contracts have economic benefit to the Company over their terms. The locational exchange will help ease electric transmission congestion across the Cascade Mountains during the winter months as PSE will take delivery of energy at a location that interconnects with PSE's transmission system in Western

Washington. At the same time, PSE will make available the quantities of power at the Mid-Columbia trading hub location.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company's earnings during the twelve months ending December 31, 2007 and December 31, 2006:

(DOLLARS IN MILLIONS)	2007	2006	CHANGE
Increase (decrease) in earnings	$ 2.7	$(0.1)	$ 2.8

The Company recorded an increase in earnings for the change in the market value of derivative instruments not meeting the normal purchase normal sale exception or cash flow hedge criteria under SFAS No. 133 of $2.7 million for 2007 compared to a decrease in earnings of $0.1 million for 2006. The increase in earnings in 2007 primarily relates to the unrealized gain associated with a physically delivered natural gas supply contract for electric generation that did not meet NPNS or cash flow hedge criteria.

The amount of unrealized gain, net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133 consisted of the following at December 31, 2007 and December 31, 2006:

(DOLLARS IN MILLIONS, NET OF TAX)	DECEMBER 31, 2007	DECEMBER 31, 2006
Other comprehensive income – unrealized gain	$ 3.4	$ 4.9

The following table presents the derivative hedges of natural gas contracts to serve natural gas customers at December 31, 2007:

	GAS DERIVATIVES	
(DOLLARS IN MILLIONS)	DECEMBER 31, 2007	DECEMBER 31, 2006
Short-term asset	$ 6.0	$ 6.7
Long-term asset	5.3	0.1
Total assets	$ 11.3	$ 6.8
Short-term liability	$ 17.3	$ 61.6
Total liabilities	$ 17.3	$ 61.6

At December 31, 2007, the Company had total assets of $11.3 million and total liabilities of $17.3 million related to hedges of natural gas contracts to serve natural gas customers. 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 hedges are realized in future periods, they will be recorded as natural gas costs under the PGA mechanism.

A hypothetical 10.0% increase in the market prices of natural gas and electricity would increase the fair value of qualifying cash flow hedges by $31.6 million, net of tax, and would decrease the fair value of those contracts marked-to-market in earnings by $0.1 million, net of tax.

ENERGY DERIVATIVE CONTRACTS GAIN(LOSS) (DOLLARS IN MILLIONS)	AMOUNTS
Fair value of contracts outstanding at December 31, 2006	$ (47.2)
Contracts realized or otherwise settled during 2007	101.7
Changes in fair value of derivatives	(52.5)
Fair value of contracts outstanding at December 31, 2007	$ 2.0

Source of Fair Value (Dollars in Millions)	Fair Value of Contracts with Settlement During Year 2008	2009-2010	2011-2012	2013 and Beyond	Total fair value
Prices actively quoted	$ (10.0)	$ --	$ --	$ --	$ (10.0)
Prices based on models and other valuation methods	--	9.9	1.4	0.7	12.0
Total	$ (10.0)	$ 9.9	$ 1.4	$ 0.7	$ 2.0

Credit Risk

The Company is exposed to credit risk primarily through buying and selling electricity and natural 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. The Company has entered into master netting arrangements 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.

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, 2007, approximately 99.8% of the counterparties comprising the sources of our energy portfolio are rated at least investment grade by the major rating agencies and 0.2% 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 anticipated 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, 2007 or 2006; 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 the Company's debt instruments are:

(Dollars in Millions)	December 31, 2007 Carrying Amount	December 31, 2007 Fair Value	December 31, 2006 Carrying Amount	December 31, 2006 Fair Value
Financial liabilities:				
Short-term debt	$ 260.5	$ 260.5	$ 328.0	$ 328.0
Short-term debt owed by PSE to Puget Energy	15.8	15.8	24.3	24.3
Long-term debt – fixed-rate[1]	2,858.4	2,623.3	2,733.4	2,823.3

1 *PSE's carrying value and fair value of fixed-rate long-term debt was the same as Puget Energy's debt in 2007 and 2006.*

The ending balance in other comprehensive income related to the forward starting swaps and previously settled treasury lock contracts at December 31, 2007 is a net loss of $8.2 million after tax and accumulated amortization. This compares to a loss of $8.5 million in other comprehensive income after tax and accumulated amortization at December 31, 2006. All financial hedge contracts of this type are reviewed by senior management and presented to the Securities Pricing Committee of the Board of Directors and are approved prior to execution.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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 Leadership 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/ Eric M. Markell	/s/ James W. Eldredge
Stephen P. Reynolds	Eric M. Markell	James W. Eldredge
Chairman, President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*	*Vice President, Controller and Chief Accounting Officer*

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the accompanying index present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

As discussed in Note 16 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation in 2006.

As discussed in Note 14 to the consolidated financial statements, the Company changed the manner in which it accounts for defined pension and other postretirement benefit plans in 2006.

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
PricewaterhouseCoopers LLP
Seattle, WA
February 29, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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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
PricewaterhouseCoopers LLP
Seattle, WA
February 29, 2008

Puget Energy Consolidated Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2007	2006	2005
Operating revenues:			
Electric	$ 1,997,829	$ 1,777,745	$ 1,612,869
Gas	1,208,029	1,120,118	952,515
Other	14,289	9,200	12,624
Total operating revenues	3,220,147	2,907,063	2,578,008
Operating expenses:			
Energy costs:			
Purchased electricity	895,592	917,801	860,422
Electric generation fuel	143,406	97,320	73,318
Residential exchange	(52,439)	(163,622)	(180,491)
Purchased gas	762,112	723,232	592,120
Net unrealized (gain) loss on derivative instruments	(2,687)	71	472
Utility operations and maintenance	403,681	354,590	333,256
Other operations and maintenance	13,636	6,362	8,884
Merger related costs	8,143	--	--
Depreciation and amortization	279,222	262,341	241,634
Conservation amortization	39,955	32,320	24,308
Taxes other than income taxes	288,492	255,797	233,788
Total operating expenses	2,779,113	2,486,212	2,187,711
Operating income	441,034	420,851	390,297
Other income (deductions):			
Other income	28,942	28,592	12,006
Charitable contributions	--	(15,000)	--
Other expense	(7,509)	(6,594)	(4,791)
Interest charges:			
AFUDC	12,614	15,874	9,493
Interest expense	(217,823)	(184,012)	(174,682)
Income from continuing operations before income taxes	257,258	259,711	232,323
Income tax (benefit) expense	72,582	92,487	86,040
Income from continuing operations	184,676	167,224	146,283
Income (loss) from discontinued segment (net of tax)	(212)	51,903	9,514
Net income before cumulative effect of accounting change	184,464	219,127	155,797
Cumulative effect of implementation of accounting change (net of tax)	--	89	(71)
Net income	$ 184,464	$ 219,216	$ 155,726
Common shares outstanding weighted-average (in thousands)	117,673	115,999	102,570
Diluted shares outstanding weighted-average (in thousands)	118,344	116,457	103,111
Basic earnings per common share before cumulative effect from accounting change	$ 1.57	$ 1.44	$ 1.43
Basic earnings per common share from discontinued operations	--	0.45	0.09
Cumulative effect from accounting change	--	--	--
Basic earnings per common share	$ 1.57	$ 1.89	$ 1.52
Diluted earnings per common share before cumulative effect from accounting change	$ 1.56	$ 1.44	$ 1.42
Diluted earnings per common share from discontinued operations	--	0.44	0.09
Cumulative effect from accounting change	--	--	--
Diluted earnings per common share	$ 1.56	$ 1.88	$ 1.51

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

Puget Energy Consolidated Balance Sheets

ASSETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2007	2006
Utility plant:		
Electric plant	$ 5,914,127	$ 5,334,368
Gas plant	2,313,477	2,146,048
Common plant	506,211	458,262
Less: Accumulated depreciation and amortization	(3,091,176)	(2,757,632)
Net utility plant	5,642,639	5,181,046
Other property and investments:		
Investment in Bonneville Exchange Power contract	33,503	37,029
Other property and investments	114,083	114,433
Total other property and investments	147,586	151,462
Current assets:		
Cash	40,797	28,117
Restricted cash	4,793	839
Accounts receivable, net of allowance for doubtful accounts	218,781	253,613
Secured pledged accounts receivable	152,000	110,000
Unbilled revenues	210,025	202,492
Purchased gas adjustment receivable	--	39,822
Materials and supplies, at average cost	62,114	43,501
Fuel and gas inventory, at average cost	99,772	115,752
Unrealized gain on derivative instruments	17,130	16,826
Prepaid income tax	44,303	--
Prepaid expense and other	11,910	9,228
Deferred income taxes	4,011	1,175
Total current assets	865,636	821,365
Other long-term assets:		
Restricted cash	--	3,814
Regulatory asset for deferred income taxes	104,928	115,304
Regulatory asset for PURPA buyout costs	140,520	167,941
Power cost adjustment mechanism	3,114	6,357
Other regulatory assets	512,103	472,003
Unrealized gain on derivative instruments	11,845	6,934
Other	170,365	139,813
Total other long-term assets	942,875	912,166
Total assets	$ 7,598,736	$ 7,066,039

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	2007	2006
Capitalization:		
(See Consolidated Statements of Capitalization)		
Common equity	$ 2,521,954	$ 2,116,029
Total shareholders' equity	2,521,954	2,116,029
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated notes	250,000	--
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	--	37,750
Long-term debt	2,428,860	2,608,360
Total redeemable securities and long-term debt	2,680,749	2,647,999
Total capitalization	5,202,703	4,764,028
Current liabilities:		
Accounts payable	310,398	379,579
Short-term debt	260,486	328,055
Current maturities of long-term debt	179,500	125,000
Accrued expenses:		
Purchased gas liability	77,864	--
Taxes	84,756	54,977
Salaries and wages	28,516	32,122
Interest	45,133	36,915
Unrealized loss on derivative instruments	27,089	70,596
Other	48,918	43,889
Total current liabilities	1,062,660	1,071,133
Long-term liabilities:		
Deferred income taxes	818,161	745,095
Unrealized loss on derivative instruments	--	415
Regulatory liabilities	210,372	191,665
Other deferred credits	304,840	293,703
Total long-term liabilities	1,333,373	1,230,878
Commitments and contingencies (Note 22 and 25)		
Total capitalization and liabilities	$ 7,598,736	$ 7,066,039

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

Puget Energy Consolidated Statements of

CAPITALIZATION

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2007	2006
Common equity:		
Common stock $0.01 par value, 250,000,000 shares authorized, 129,678,489 and 116,576,636 shares outstanding at December 31, 2007 and 2006	$ 1,297	$ 1,166
Additional paid-in capital	2,278,500	1,969,032
Earnings reinvested in the business	240,079	172,529
Accumulated other comprehensive income (loss) – net of tax	2,078	(26,698)
Total common equity	2,521,954	2,116,029
Preferred stock subject to mandatory redemption – cumulative – $100 par value: *		
4.84% series –150,000 shares authorized, 14,583 shares outstanding at December 31, 2007 and 2006	1,458	1,458
4.70% series –150,000 shares authorized, 4,311 shares outstanding at December 31, 2007 and 2006	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	--	37,750
Long-term debt:		
First mortgage bonds and senior notes	2,446,500	2,571,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Junior subordinated notes	250,000	--
Long-term debt due within one year	(179,500)	(125,000)
Total long-term debt excluding current maturities	2,678,860	2,608,360
Total capitalization	$ 5,202,703	$ 4,764,028

** 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, 2007, 2006 & 2005	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
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 income	--	--	--	--	21,840	21,840
Balance at December 31, 2005	115,695,463	$ 1,157	$ 1,948,975	$ 69,407	$ 7,508	$ 2,027,047
Net income	--	--	--	219,216	--	219,216
Common stock dividend declared	--	--	--	(116,094)	--	(116,094)
Common stock issued:						
Dividend reinvestment plan	614,548	6	13,481	--	--	13,487
Employee plans	266,625	3	6,576	--	--	6,579
Other comprehensive loss	--	--	--	--	(15,553)	(15,553)
Adjustment to initially apply SFAS No. 158, net of tax of $(12,420)	--	--	--	--	(18,653)	(18,653)
Balance at December 31, 2006	116,576,636	$ 1,166	$ 1,969,032	$ 172,529	$ (26,698)	$ 2,116,029
Net income	--	--	--	184,464	--	184,464
Common stock dividend declared	--	--	--	(116,914)	--	(116,914)
Common stock issued:						
New issuance	12,500,000	125	293,070	--	--	293,195
Dividend reinvestment plan	399,993	4	9,777	--	--	9,781
Employee plans	201,860	2	6,621	--	--	6,623
Other comprehensive income	--	--	--	--	28,776	28,776
Balance at December 31, 2007	129,678,489	$ 1,297	$ 2,278,500	$ 240,079	$ 2,078	$ 2,521,954

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

Puget Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS)

FOR YEARS ENDED DECEMBER 31	2007	2006	2005
Net income	$ 184,464	$ 219,216	$ 155,726
Other comprehensive income (loss):			
Foreign currency translation adjustment, net of tax of $0, $(176) and $(49), respectively	--	(327)	(91)
Unrealized gain from pension and postretirement plans, net of tax of $16,083, $2,376 and $0, respectively	29,869	2,873	925
Net unrealized gain (loss) on energy derivative instruments during the period, net of tax of $(6,776), $(17,669) and $26,799 respectively	(12,584)	(32,813)	49,770
Reversal of net unrealized gains (losses) on energy derivative instruments settled during the period, net of tax of $6,017, $(2,972) and $(10,319), respectively	11,174	(5,519)	(19,164)
Settlement of financing cash flow hedge contracts, net of tax of $0, $7,239 and $(12,363), respectively	--	13,443	(22,960)
Amortization of financing cash flow hedge contracts to earnings, net of tax of $171, $289 and $245, respectively	317	537	455
Deferral of energy cash flow hedges related to the power cost adjustment mechanism, net of tax of $0, $3,367 and $6,949, respectively	--	6,253	12,905
Other comprehensive income (loss)	28,776	(15,553)	21,840
Comprehensive income	$ 213,240	$ 203,663	$ 177,566

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	2007	2006	2005
Operating activities:			
Net income	$ 184,464	$ 219,216	$ 155,726
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	279,222	262,341	241,634
Conservation amortization	39,955	32,299	24,378
Deferred income taxes and tax credits, net	66,820	20,613	(56,852)
Power cost adjustment mechanism	3,243	12,023	(18,380)
Amortization of gas pipeline capacity assignment	(10,943)	(10,632)	--
Non cash return on regulatory assets	(10,194)	(12,438)	--
Net unrealized loss on derivative instruments	(2,687)	71	472
Gain on sale of InfrastruX	--	(29,765)	--
Impairment on InfrastruX investment	--	(7,269)	7,269
Other	16,117	(13,104)	(18,306)
Cash collateral paid from (returned to) energy suppliers	--	(22,020)	15,700
Gas pipeline capacity assignment	--	--	55,000
BPA prepaid transmission	--	--	(10,750)
Cash receipt from lease purchase option settlement	18,859	--	--
Chelan PUD contract initiation prepayment	--	(89,000)	--
Residential exchange program	(28,133)	(5,595)	(4,941)
Goldendale deferred costs	(11,505)	--	--
Storm damage deferred costs	(29,274)	(92,331)	--
Change in certain current assets and liabilities:			
Accounts receivable and unbilled revenue	(4,652)	(78,179)	(217,861)
Materials and supplies	(18,613)	(6,093)	(4,945)
Fuel and gas inventory	15,981	(24,694)	(25,163)
Prepaid income taxes	(44,303)	--	--
Prepayments and other	(2,681)	(4,319)	273
Purchased gas receivable / payable	117,685	27,513	(48,246)
Accounts payable	(52,678)	36,038	119,416
Taxes payable	29,779	(53,826)	38,047
Tenaska disallowance reserve	--	--	(3,156)
Accrued expenses and other	7,539	24,658	6,496
Net cash provided by operating activities	564,001	185,507	255,811
Investing activities:			
Construction and capital expenditures – excluding equity AFUDC	(737,258)	(749,516)	(583,594)
Energy efficiency expenditures	(43,398)	(33,865)	(24,428)
Restricted cash	(141)	(3,605)	586
Cash proceeds from property sales	6,468	936	24,291
Refundable cash received for customer construction projects	16,835	12,253	9,869
Gross proceeds from sale of InfrastruX, net of cash disposed	--	263,575	--
Other	495	5,500	5,906
Net cash used by investing activities	(756,999)	(504,722)	(567,370)
Financing activities:			
Change in short-term debt and leases, net	(67,569)	290,224	36,512
Dividends paid	(108,434)	(104,332)	(88,071)
Issuance of common stock	300,544	5,878	317,607
Issuance of bonds and notes	250,000	550,000	400,000
Payments to minority shareholders of InfrastruX	--	(10,451)	--
InfrastruX debt redeemed	--	(141,221)	--
Redemption of trust preferred stock	(37,750)	(200,000)	(42,500)
Redemption of bonds, notes and leases	(125,000)	(83,875)	(260,615)
Settlement of cash flow hedge of interest rate derivative	--	20,682	(35,323)
Issuance and redemption costs of bonds and other	(6,113)	(2,467)	(12,928)
Net cash provided by financing activities	205,678	324,438	314,682
Net increase in cash	12,680	5,223	3,123
Cash at beginning of year	28,117	22,894	19,771
Cash at end of year	$ 40,797	$ 28,117	$ 22,894
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 196,180	$ 167,789	$ 182,054
Cash payments for income taxes	26,897	129,100	126,807

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	2007	2006	2005
Operating revenues:			
Electric	$ 1,997,829	$ 1,777,745	$ 1,612,869
Gas	1,208,029	1,120,118	952,515
Non-utility operating revenues	14,289	9,200	12,624
Total operating revenues	3,220,147	2,907,063	2,578,008
Operating expenses:			
Energy costs:			
Purchased electricity	895,592	917,801	860,422
Electric generation fuel	143,406	97,320	73,318
Residential exchange	(52,439)	(163,622)	(180,491)
Purchased gas	762,112	723,232	592,120
Unrealized (gain) loss on derivative instruments	(2,687)	71	472
Utility operations and maintenance	403,681	354,590	333,256
Non-utility expense and other	12,429	4,531	7,531
Depreciation and amortization	279,222	262,341	241,634
Conservation amortization	39,955	32,320	24,308
Taxes other than income taxes	288,492	255,797	233,788
Total operating expenses	2,769,763	2,484,381	2,186,358
Operating income	450,384	422,682	391,650
Other income (deductions):			
Other income	28,938	28,236	12,006
Other expense	(7,509)	(6,594)	(4,791)
Interest charges:			
AFUDC	12,614	15,874	9,493
Interest expense	(217,823)	(184,013)	(174,458)
Interest expense on Puget Energy note	(1,296)	(845)	--
Income before income taxes	265,308	275,340	233,900
Income tax expense	74,181	98,689	87,060
Net income before cumulative effect of accounting change	191,127	176,651	146,840
Cumulative effect of implementation of accounting change (net of tax)	--	89	(71)
Net income	$ 191,127	$ 176,740	$ 146,769

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	2007	2006
Utility plant:		
Electric plant	$ 5,914,127	$ 5,334,368
Gas plant	2,313,477	2,146,048
Common plant	506,211	458,262
Less: Accumulated depreciation and amortization	(3,091,176)	(2,757,632)
Net utility plant	5,642,639	5,181,046
Other property and investments:		
Investment in Bonneville Exchange Power contract	33,503	37,029
Other property and investments	114,083	114,433
Total other property and investments	147,586	151,462
Current assets:		
Cash	40,773	28,092
Restricted cash	798	839
Accounts receivable, net of allowance for doubtful accounts	219,345	253,613
Secured pledged accounts receivable	152,000	110,000
Unbilled revenues	210,025	202,492
Purchased gas adjustment receivable	--	39,822
Materials and supplies, at average cost	62,114	43,501
Fuel and gas inventory, at average cost	99,772	115,752
Unrealized gain on derivative instruments	17,130	16,826
Prepaid income taxes	41,814	--
Prepaid expenses and other	11,365	8,659
Deferred income taxes	4,011	1,175
Total current assets	859,147	820,771
Other long-term assets:		
Regulatory asset for deferred income taxes	104,928	115,304
Regulatory asset for PURPA buyout costs	140,520	167,941
Power cost adjustment mechanism	3,114	6,357
Other regulatory assets	512,103	472,003
Unrealized gain on derivative instruments	11,845	6,934
Other	170,328	139,595
Total other long-term assets	942,838	908,134
Total assets	$ 7,592,210	$ 7,061,413

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	2007	2006
Capitalization:		
(See Consolidated Statements of Capitalization):		
Common equity	$ 2,504,091	$ 2,092,283
Total shareholder's equity	2,504,091	2,092,283
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated notes	250,000	--
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	--	37,750
Long-term debt	2,428,860	2,608,360
Total redeemable securities and long-term debt	2,680,749	2,647,999
Total capitalization	5,184,840	4,740,282
Current liabilities:		
Accounts payable	310,083	379,494
Short-term debt	260,486	328,055
Short-term note owed to Puget Energy	15,766	24,303
Current maturities of long-term debt	179,500	125,000
Accrued expenses:		
Purchased gas liability	77,864	--
Taxes	84,756	55,365
Salaries and wages	28,516	31,591
Interest	45,209	37,031
Unrealized loss on derivative instruments	27,089	70,596
Other	48,918	43,889
Total current liabilities	1,078,187	1,095,324
Long-term liabilities:		
Deferred income taxes	821,382	749,033
Unrealized loss on derivative instruments	--	415
Regulatory liabilities	210,372	191,665
Other deferred credits	297,429	284,694
Total long-term liabilities	1,329,183	1,225,807
Commitments and contingencies (Note 22 and 25)		
Total capitalization and liabilities	$ 7,592,210	$ 7,061,413

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	2007	2006
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	1,297,076	996,737
Earnings reinvested in the business	345,899	263,206
Accumulated other comprehensive income (loss) – net of tax	2,078	(26,698)
Total common equity	2,504,091	2,092,283
Preferred stock subject to mandatory redemption – cumulative -		
$100 par value:*		
4.84% series – 150,000 shares authorized,		
14,583 shares outstanding at December 31, 2007 and 2006	1,458	1,458
4.70% series – 150,000 shares authorized,		
4,311 shares outstanding at December 31, 2007 and 2006	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	--	37,750
Long-term debt:		
First mortgage bonds and senior notes	2,446,500	2,571,500
Pollution control revenue bonds:		
Revenue refunding 2003 series, due 2031	161,860	161,860
Junior subordinated notes	250,000	--
Long-term debt due within one year	(179,500)	(125,000)
Total long-term debt excluding current maturities	2,678,860	2,608,360
Total capitalization	$ 5,184,840	$ 4,740,282

**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, 2007, 2006 & 2005	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Amount
	Shares	Amount				
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 loss	--	--	--	--	21,931	21,931
Balance at December 31, 2005	85,903,791	$859,038	$ 924,154	$196,248	$ 7,181	$1,986,621
Net income	--	--	--	176,740	--	176,740
Common stock dividend declared	--	--	--	(109,782)	--	(109,782)
Investment received from Puget Energy	--	--	72,583	--	--	72,583
Other comprehensive loss	--	--	--	--	(15,226)	(15,226)
Adjustment to initially apply SFAS No. 158, net of tax of $(12,420)	--	--	--	--	(18,653)	(18,653)
Balance at December 31, 2006	85,903,791	$859,038	$ 996,737	$263,206	$(26,698)	$2,092,283
Net income	--	--	--	191,127	--	191,127
Common stock dividend declared	--	--	--	(108,434)	--	(108,434)
Investment received from Puget Energy	--	--	300,339	--		300,339
Other comprehensive income	--	--	--	--	28,776	28,776
Balance at December 31, 2007	85,903,791	$859,038	$1,297,076	$345,899	$ 2,078	$2,504,091

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

Puget Sound Energy Consolidated Statements of

COMPREHENSIVE INCOME

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2007	2006	2005
Net income	$ 191,127	$ 176,740	$ 146,769
Other comprehensive income (loss):			
Unrealized gain from pension and postretirement plans, net of tax of $16,083, $2,376 and $0, respectively	29,869	2,873	925
Net unrealized gains (losses) on energy derivative instruments during the period, net of tax of $(6,776), $(17,669), and $26,799, respectively	(12,584)	(32,813)	49,770
Reversal of net unrealized gains (losses) on energy derivative instruments settled during the period, net of tax of $6,017, $(2,972) and $(10,319), respectively	11,174	(5,519)	(19,164)
Settlement of financing cash flow hedge contracts, net of tax of $0, $7,239 and $(12,363), respectively	--	13,443	(22,960)
Amortization of financing cash flow hedge contracts to earnings, net of tax of $171, $289 and $245, respectively	317	537	455
Deferral of energy cash flow hedges related to power cost adjustment mechanism, net of tax of $0, $3,367 and $6,949, respectively	--	6,253	12,905
Other comprehensive income (loss)	28,776	(15,226)	21,931
Comprehensive income	$ 219,903	$ 161,514	$ 168,700

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	2007	2006	2005
Operating activities:			
Net income	$ 191,127	$ 176,740	$ 146,769
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	279,222	262,341	241,634
Conservation amortization	39,955	32,299	24,378
Deferred income taxes and tax credits, net	66,102	34,283	(57,597)
Power cost adjustment mechanism	3,243	12,023	(18,380)
Amortization of gas pipeline capacity	(10,943)	(10,632)	--
Non cash return on regulatory assets	(10,194)	(12,438)	--
Net unrealized loss on derivative instruments	(2,687)	71	472
Other	17,252	(9,369)	(24,240)
Cash collateral paid from (returned to) energy suppliers	--	(22,020)	15,700
Gas pipeline capacity assignment	--	--	55,000
BPA prepaid transmission	--	--	(10,750)
Cash receipt from lease purchase option settlement	18,859	--	--
Chelan PUD contract initiation payment	--	(89,000)	--
Residential exchange program	(28,133)	(5,595)	(4,941)
Goldendale deferred costs	(11,505)	--	--
Storm damage deferred costs	(29,274)	(92,331)	--
Change in certain current assets and current liabilities:			
Accounts receivable and unbilled revenue	(5,215)	(64,961)	(221,960)
Materials and supplies	(18,613)	(7,010)	(4,808)
Fuel and gas inventory	15,981	(24,694)	(25,163)
Prepaid income taxes	(41,814)	--	--
Prepayments and other	(2,706)	(1,636)	(776)
Purchased gas receivable / payable	117,685	27,513	(48,246)
Accounts payable	(52,908)	33,004	116,743
Taxes payable	29,391	(56,535)	30,265
Tenaska disallowance reserve	--	--	(3,156)
Accrued expenses and other	8,164	30,588	(2,201)
Net cash provided by operating activities	572,989	212,641	208,743
Investing activities:			
Construction expenditures – excluding equity AFUDC	(737,258)	(745,239)	(568,381)
Energy efficiency expenditures	(43,398)	(33,865)	(24,428)
Restricted cash	495	208	586
Cash received from property sales	6,468	936	24,291
Refundable cash received for customer construction projects	16,835	12,253	9,869
Other	40	5,500	6,006
Net cash used by investing activities	(756,818)	(760,207)	(552,057)
Financing activities:			
Change in short-term debt, net	(67,569)	287,055	41,000
Dividends paid	(108,434)	(109,782)	(89,199)
Issuance of bonds and notes	250,000	550,000	400,000
Loan (payment) from/to Puget Energy	(8,537)	24,303	--
Redemption of trust preferred stock	(37,750)	(200,000)	(42,500)
Redemption of bonds and notes	(125,000)	(81,000)	(231,000)
Settlement of cash flow hedge interest rate derivative	--	20,682	(35,323)
Investment from Puget Energy	297,073	70,114	314,687
Issuance and redemption cost of bonds and other	(3,273)	(2,423)	(10,597)
Net cash provided by financing activities	196,510	558,949	347,068
Net increase in cash from net income	12,681	11,383	3,754
Cash at beginning of year	28,092	16,709	12,955
Cash at end of year	$ 40,773	$ 28,092	$ 16,709
Supplemental cash flow information:			
Cash payments for interest (net of capitalized interest)	$ 196,180	$ 164,389	$ 172,986
Cash payments for income taxes	26,897	123,100	126,591

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, Inc. (Puget Energy) is a holding company that owns Puget Sound Energy, Inc. (PSE) and until May 7, 2006, a 90.9% interest in InfrastruX Group, Inc. (InfrastruX). PSE is a public utility incorporated in the state of Washington that furnishes electric and natural gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region.

The 2007 consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiary, PSE. 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 to current year presentations with no effect on total equity or net income. The reclassification relates to the income statements of Puget Energy and PSE, which have been changed from a utility presentation format based on Federal Energy Regulatory Commission (FERC) guidelines to a presentation based on generally accepted accounting principles (GAAP).

The 2006 consolidated financial statements of Puget Energy reflect the accounts of Puget Energy and its subsidiaries, PSE and InfrastruX. Puget Energy holds all the common shares of PSE and until May 7, 2006, 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 are presented as discontinued operations. At the time that it was owned by Puget Energy, InfrastruX was a non-regulated utility construction service company incorporated in the state of Washington, which provides construction services to the electric and natural gas utility industries primarily in the Midwest, Texas, south-central and eastern United States regions.

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, 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 Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). 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 2007, 2006 and 2005; depreciable gas utility plant was 3.4% in 2007, 3.3% in 2006 and 3.4% in 2005; and depreciable common utility plant was 5.1% in 2007, 5.1% in 2006 and 4.8 % in 2005. 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 $4.8 million and $0.8 million at December 31, 2007 and 2006, respectively. The restricted cash balance in both 2007 and 2006 includes $0.8 million which represents funds held by Puget Western, Inc., a PSE subsidiary, for a real estate development project. $4.0 million represents management's estimate of the aggregate fair value of the amount potentially payable under certain representations and warranties made by InfrastruX concerning its business.

MATERIAL AND SUPPLIES

Material and supplies consists primarily of materials and supplies used in the operation and maintenance of electric and natural 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 natural gas customers. Fuel inventory consists of coal, diesel, and natural gas used for generation. Gas inventory consists of natural gas and liquefied natural gas (LNG) 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). 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. In most cases, the Company classifies regulatory assets and liabilities as long-term assets or liabilities. The exception is the purchased gas adjustment payable which is a current liability.

The Company was allowed a return on the net regulatory assets and liabilities of 8.75% for electric rates beginning July 1, 2002 and natural gas rates beginning September 1, 2002 through March 3, 2005 and 8.4%, or 7.01% after-tax, for both electric and natural gas rates for the period March 4, 2005 through January 12, 2007. Effective January 13, 2007 based on the 2006 general rate case, the Company is allowed a return on the net regulatory assets and liabilities of 8.4% or 7.06% after tax, for both electric and natural gas rates. The net regulatory assets and liabilities at December 31, 2007 and 2006 included the following:

(Dollars in Millions)	Remaining Amortization Period	2007	2006
PURPA electric energy supply contract buyout costs	0.5 to 4 years	$ 140.6	$ 167.9
Storm damage costs – electric	*	127.4	101.1
Chelan PUD contract initiation	**	105.2	95.5
Deferred income taxes	***	104.9	115.3
White River relicensing and other costs	****	72.5	69.1
Environmental remediation	****	37.8	36.3
Deferred AFUDC	30 years	36.3	33.3
Residential Exchange	****	35.7	--
Investment in Bonneville Exchange Power contract	9.5 years	33.5	37.0
Tree watch costs	7.3 years	15.3	19.8
Colstrip common property	16.5 years	11.8	12.5
Goldendale	****	11.5	--
Hopkins Ridge prepaid transmission upgrade	*****	7.2	8.9
PGA deferral of unrealized (gain) losses on derivative instruments	***	6.0	54.8
Carrying costs on income tax payments	2 years	3.4	6.2
Power cost adjustment (PCA) mechanism	***	3.1	6.4
Various other regulatory assets	1 to 28.5 years	42.0	34.6
Purchased gas adjustment (PGA) receivable	***	--	39.8
Total regulatory assets		$ 794.2	$ 838.5
Cost of removal	******	$ (137.9)	$ (127.1)
Purchased gas adjustment (PGA) payable	***	(77.9)	--
Deferred credit gas pipeline capacity	4 to 10.8 years	(33.4)	(44.4)
Summit Purchase Option Buy-Out	****	(18.9)	--
Deferred gains on property sales	2 years	(12.7)	(11.1)
Gas supply contract settlement	0.5 year	(1.9)	(5.7)
Various other regulatory liabilities	3.1 to 8.5 years	(5.6)	(3.3)
Total regulatory liabilities		$ (288.3)	$ (191.6)
Net regulatory assets and liabilities		$ 505.9	$ 646.9

* *Amortization period for storm costs deferred in 2006 to be determined in a future Washington Commission rate proceeding.*
** *Amortization period will start in 2011 for a 20-year period.*
*** *Amortization period varies depending on timing of underlying transactions.*
**** *Amortization period to be determined in a future Washington Commission rate proceeding.*
***** *Amortization varies and based upon BPA tariff rate and FERC interest rate.*
****** *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

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 Financial Accounting Standards Board (FASB) Statement No. 71" (SFAS No. 101). 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 (SEC), the Company reclassified from accumulated depreciation to a regulatory liability $137.9 million and $127.1 million in 2007 and 2006, 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 to interest expense and as a non-cash item to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rate allowed by the Washington Utilities and Transportation Commission (Washington Commission) for natural gas utility plant additions was 8.4% 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 8.4% 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 $4.4 million for 2007, $2.7 million for 2006 and $2.8 million for 2005. The deferred asset is being amortized over the average useful life of the Company's non-project electric utility plant.

California Receivable

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. The amount of the receivable, $21.1 million at December 31, 2007 is subject to the outcome of the ongoing litigation.

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 revenue 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. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission.

PSE collected Washington State excise taxes (which are a component of general retail rates) and municipal taxes of $229.0 million, $203.7 million and $178.0 million for 2007, 2006 and 2005, respectively. The Company's policy is to report such taxes on a gross basis in operating revenues and taxes other than income taxes in the accompanying consolidated statements of income.

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. 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 at December 31, 2007 and 2006 was $5.5 million and $2.8 million, respectively.

Self-Insurance

The Company currently has no insurance coverage for storm damage and environmental contamination that would occur in a current year on company-owned property. The Company 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 $7.0 million of qualifying storm damage costs for collection in future rates if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

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" (SFAS No. 109). Uncertain tax positions are accounted for under FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). The Company classifies interest as interest expense and penalties as other expense in the financial statements.

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 reducing energy margins. The impact of load reductions is adjusted in rates at each general rate case.

Since 1995, the Company has been authorized by the Washington Commission to defer natural 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, natural gas energy efficiency expenditures have no impact on earnings.

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.

As part of the Company's 2006 General Rate Case, the Washington Commission agreed to have the Company collect an incentive through rate riders if the Company exceeded the annual 2007 electric annual baseline savings goal of 18.3 aMW. In 2007, PSE achieved 25.4 aMW of cost-effective energy savings thus exceeding its goals and earning an electric incentive of $3.4 million. The Company recognized $2.5 million in other income for the year ended December 31, 2007, and will collect this amount from rate riders from April 2008 through March 2009. The remaining 25%, still subject to evaluation, was not recognized into income for the year ended December 31, 2007 because the evaluation process was not complete. Once the evaluation process is completed, then the remaining amount will be recognized into income, and the Company will collect this amount from rate riders from April 2009 through March 2010.

RATE ADJUSTMENT MECHANISMS

The Company has a Power Cost Adjustment (PCA) mechanism that provides for a rate adjustment process 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. 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" (SFAS No. 133), are deferred in proportion to the cost-sharing arrangement under the PCA mechanism. On January 10, 2007, the Washington Commission approved the PCA mechanism with the same annual graduated scale but without a cap on excess power costs.

The graduated scale is as follows:

Annual Power Cost Variability	July – 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 was capped at a cumulative $40.0 million plus 1% of the excess. Power cost variation after December 31, 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 natural gas supplies and natural gas transportation contracts and costs 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 the PGA mechanism rates, including interest.

Natural Gas Off-System Sales and Capacity Release

The Company contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural 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 natural 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 natural gas sales, exchanges and capacity releases. The Company sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural 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 natural gas.

Accounting for Derivatives

The Company follows the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended by SFAS No. 138 and SFAS No. 149 which require 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 (NPNS) exception for the purpose of serving retail load. However, those contracts that do not meet the NPNS 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 natural gas for the Company's retail natural 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.

STOCK-BASED COMPENSATION

Prior to 2006, the Company had various stock-based compensation plans which were accounted for according to Accounting Principles Board (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). 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" (SFAS No. 148). The Company applied SFAS No. 123 accounting to stock compensation awards granted subsequent to January 1, 2003, while grants prior to 2003 continued to be accounted for using the intrinsic value method of APB No. 25. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R, "Share-Based Payment" (SFAS No. 123R), using the modified-prospective transition method. Under that transition method, compensation cost recognized in 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123 and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. Results for prior periods have not been restated, as provided for under the modified-prospective method.

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 as of December 31, 2005 would have been as follows:

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS) YEARS ENDED DECEMBER 31	2005
Net income, as reported	$ 155,726
Add: Total stock-based employee compensation expense included in net income, net of tax	1,652
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(2,195)
Pro forma net income	$ 155,183
Earnings per common share:	
Basic as reported	$ 1.52
Diluted as reported	$ 1.51
Basic pro forma	$ 1.51
Diluted pro forma	$ 1.51

DEBT RELATED COSTS

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

EARNINGS PER COMMON SHARE (PUGET ENERGY ONLY)

Basic earnings per common share has been computed based on weighted-average common shares outstanding of 117,673,000, 115,999,000 and 102,570,000 for 2007, 2006 and 2005, respectively. Diluted earnings per common share has been computed based on weighted-average common shares outstanding of 118,344,000, 116,457,000 and 103,111,000 for 2007, 2006 and 2005, respectively, which includes the dilutive effect of securities related to employee stock-based compensation plans. In 2007, 1,300 shares related to stock options were excluded from the diluted weighted-average common share calculation due to their anti-dilutive effect. In 2006, 46,000 shares related to stock options were excluded from the diluted weighted-average common share calculation due to their antidilutive effect.

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 results of PSE Funding are consolidated in the financial statements of PSE. 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 Receivables 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 $200.0 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 $152.0 million of loans secured by accounts receivable pledged as collateral at December 31, 2007.

CONSOLIDATED STATEMENTS OF CASH FLOWS

PSE funds cash dividends paid to the shareholders of Puget Energy. These funds are reflected in the Consolidated Statement of Cash Flows of Puget Energy as if Puget Energy received the cash from PSE and paid the dividends directly to the shareholders.

COMPREHENSIVE INCOME

Comprehensive income includes net income, the minimum pension liability, unrealized gains and losses on derivative instruments, reversals of unrealized gains and losses on derivative instruments, settlements and amortization of cash flow hedge contracts and deferrals of cash flow hedges related to the power cost mechanism. The following table presents the Company's accumulated other comprehensive gain (loss) net of tax at December 31:

(DOLLARS IN THOUSANDS)	2007	2006
Unrealized gains (losses) on derivatives during the period	$ (3,000)	$ 9,584
Reversal of unrealized (gains) losses on derivatives during the period	6,483	(4,691)
Adjustment to PCA	--	--
Settlement of cash flow hedge contract	13,443	13,447
Amortization of cash flow hedge contracts	(21,652)	(21,972)
Minimum pension liability adjustment	--	(4,413)
Unrealized gain and prior service cost on pension plans	6,804	--
Adjustment to initially apply SFAS No. 158	--	(18,653)
Total Puget Energy, net of tax	$ 2,078	$ (26,698)

NOTE 2. *New Accounting Pronouncements*

On September 15, 2006, FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157), which clarifies how companies should use fair value measurements in accordance with GAAP for recognition and disclosure. SFAS No. 157 establishes a common definition of fair value and a framework for measuring fair value under GAAP, along with expanding disclosures about fair value measurements to eliminate differences in current practice that exist in measuring fair value under the existing accounting standards. The definition of fair value in SFAS No. 157 retains the notion of exchange price; however, it focuses on the price that would be received to sell the asset or paid to transfer the liability (i.e., an exit price), rather than the price that would be paid to acquire the asset or received to assume the liability (i.e., an entry price). Under SFAS No. 157, a fair value measure should reflect all of the assumptions that market participants would use in pricing the asset or liability, including assumptions about the risk inherent in a particular valuation technique, the effect of a restriction on the sale or use of an asset, and the risk of nonperformance. To increase consistency and comparability in fair value measures, SFAS No. 157 establishes a three-level fair value hierarchy to prioritize the inputs used in valuation techniques between observable inputs that reflect quoted prices in active markets, inputs other than quoted prices with observable market data, and unobservable data (e.g., a company's own data). SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, which will be the year beginning January 1, 2008, for the Company. SFAS No. 157 standardizes the measurement of fair value when it is required under GAAP, a framework for measuring fair value and expands disclosure about such fair value measurements. On February 6, 2008, the FASB decided to issue a final FASB Staff Position (FSP) that would partially defer the effective date of SFAS No. 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value, except for those that are recognized or disclosed at fair value on an annual or more frequent basis. The Company adopted SFAS No. 157 on January 1, 2008, prospectively, as required by the Statement, with certain exceptions, including the following noted in paragraph 37 (a) of the statement, "A financial instrument that was measured at fair value at initial recognition under Statement 133 using the transaction price in accordance with the guidance in footnote 3 of EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," prior to the initial adoption of this Statement (EITF No. 02-3). At the date this Statement is initially applied to the financial statements, a difference between the carrying amounts and the fair values of those instruments shall be recognized as a cumulative-effect adjustment to the opening balance of retained earnings.

The Company estimates that the impact of the adoption of SFAS No. 157 to its statement of financial position and results of operations to be a cumulative effect adjustment to retained earnings of $9.0 million before tax as a result of recording a deferred loss on net derivative assets and liabilities.

On September 29, 2006, FASB issued SFAS No. 158, "Employer's Accounting for Retired Benefit Pension and Other Postretirement Plans." See Note 14, "Retirement Benefits" for discussion of this statement.

In July 2006, FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109" (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." FIN 48 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, the tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. Second, a tax position, that meets the recognition threshold, should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. As of the date of adoption, the Company had no material unrecognized tax benefits. As of December 31, 2007, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

In December 2004, FASB issued SFAS No. 123R, which revises SFAS No. 123. 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. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R, using the modified-prospective transition method.

In March 2005, FASB issued Interpretation No. 47 (FIN 47), which finalized a proposed interpretation of SFAS No. 143, "Accounting for Conditional Asset Retirement Obligations" (SFAS No. 143). 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 and Corporate Guarantees (Puget Energy Only)*

On May 7, 2006, Puget Energy sold InfrastruX to an affiliate of Tenaska Power Fund, L.P. (Tenaska). After repayment of debt, adjustments for working capital, transaction costs and distributions to minority interests, Puget Energy received after-tax cash proceeds of approximately $95.9 million for its 90.9% interest in InfrastruX in the second quarter 2006. The sale resulted in an after-tax gain of $29.8 million for the twelve months ended December 31, 2006. Puget Energy accounted for InfrastruX as a discontinued operation under SFAS No. 144 in 2005 and 2006.

As part of the transaction, Puget Energy made certain representations and warranties concerning InfrastruX. Puget Energy obtained a representation and warranty insurance policy and deposited $3.7 million into an escrow account to serve as retention under the policy. At December 31, 2007, restricted cash in the escrow account was $4.0 million, which is included in the accompanying balance sheets, representing management's estimate of the aggregate fair value of Puget Energy's maximum exposure related to those representations and warranties. Should Tenaska make any such claims against Puget Energy, payment for the claims would be made from the escrow account, and total payments are limited to $3.7 million plus any interest earned while the funds are held in the escrow account. The obligation expires May 7, 2008.

Puget Energy also agreed to indemnify Tenaska for certain potential future losses related to one of InfrastruX's subsidiary companies. Under the indemnity agreement, Puget Energy is also liable for refunding a portion of the purchase price paid by Tenaska for InfrastruX if the subsidiary does not achieve certain operating results during the measurement year. The maximum obligation of Puget Energy for defense costs and a refund of a portion of the purchase price is capped at $15.0 million. Tenaska has notified Puget Energy that 2008 will be the measurement year for purposes of calculating the potential purchase price refund obligation. At December 31, 2007, a liability in the amount of $3.2 million is included in the accompanying balance sheets; that amount represents Puget Energy's estimate of the fair value of the amount potentially payable using a probability-weighted approach to a range of future cash flows. Puget Energy has made payments totaling $1.8 million related to the guarantee. The obligation expires May 7, 2011.

Puget Energy's accounting policy for its representations and warranties loss reserve and the indemnity agreement is to reduce the loss reserve only when the guarantee expires or is settled. Any increase to the loss reserves subsequent to the initial recognition would be determined if it is probable that a future event will occur confirming the additional loss and the amount of the additional loss can be estimated.

	Twelve Months Ended December 31,		
(Dollars in Thousands)	2007	2006[1]	2005
Revenues	$ --	$ 138,573	$ 393,294
Goodwill impairment	--	--	--
Operating expenses (including interest expense)	--	(128,605)	(356,934)
Pre-tax income	--	9,968	36,360
Income tax expense	--	(3,544)	(12,204)
Puget Energy carrying value adjustment of InfrastruX	--	7,269	(7,269)
Puget Energy cost of sale related to InfrastruX, net of tax of $(114), $(505) and $(2,799)	(212)	(937)	(5,195)
Puget Energy deferred tax basis adjustment of InfrastruX	--	9,966	--
Gain on sale, net of tax of $0, $16,027 and $0	--	29,765	--
Minority interest in income of discontinued operations	--	(584)	(2,178)
Income (loss) from discontinued operations	$ (212)	$ 51,903	$ 9,514

1 *Results for January 1, 2006 to May 7, 2006, the date InfrastruX was sold.*

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) and $6.7 million ($4.3 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for 2006 and 2005, respectively. Puget Energy recorded $0.2 million of amortization expense related to the intangible assets of InfrastruX for 2005.

NOTE 4. *Utility and Non-Utility Plant*

UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	ESTIMATED USEFUL LIFE (YEARS)	2007	2006
Electric, gas and common utility plant classified by prescribed accounts at original cost:			
Distribution plant	10-50	$ 5,107,272	$ 4,887,304
Production plant	35-125	2,021,239	1,694,569
Transmission plant	45-65	334,958	331,210
General plant	5-35	372,369	367,806
Whitehorn capital lease	3	22,840	23,004
Construction work in progress	NA	267,594	206,459
Intangible plant (including capitalized software)	3-50	322,005	297,939
Plant acquisition adjustment	NA	77,871	77,871
Underground storage	25-60	24,492	24,389
Liquefied natural gas storage	25-45	14,310	14,217
Plant held for future use	NA	8,623	8,315
Other	NA	6,299	5,595
Plant not classified	NA	153,943	--
Less: accumulated provision for depreciation		(3,091,176)	(2,757,632)
Net utility plant		$ 5,642,639	$ 5,181,046

Jointly owned generating plant service costs are included in utility plant service cost. 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, 2007. These amounts are also included in the Utility Plant table above.

JOINTLY OWNED GENERATING PLANTS (DOLLARS IN THOUSANDS)	ENERGY SOURCE (FUEL)	COMPANY'S OWNERSHIP SHARE	COMPANY'S SHARE: PLANT IN SERVICE AT COST	COMPANY'S SHARE: ACCUMULATED DEPRECIATION
Colstrip Units 1 & 2	Coal	50%	$ 230,216	$ (147,475)
Colstrip Units 3 & 4	Coal	25%	480,849	(277,909)
Colstrip Units 1 – 4 Common Facilities	Coal	*	252	(162)
Frederickson 1	Gas	49.85%	73,772	(8,712)

* *The Company's ownership is 50% for Colstrip Units 1 & 2 and 25% for Colstrip Units 3 & 4.*

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.

NON-UTILITY PLANT (DOLLARS IN THOUSANDS) AT DECEMBER 31	2007	2006
Non-utility plant	$ 3,040	$ 2,948
Less: accumulated provision for depreciation	(445)	(446)
Net non-utility plant	$ 2,595	$ 2,502

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 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 ARO.

FIN 47 also requires that if an entity has any ARO for which no amount has been recognized, the existence of the ARO must be disclosed with the reasons why the liability has not been recognized.

Prior to the adoption of FIN 47, the Company recognized an obligation to:

- dismantle two leased electric generation turbine units and deliver the turbines to the nearest railhead at the termination of the lease in 2009;
- remove certain structures as a result of re-negotiations with the Department of Natural Resources of a now expired lease;
- restore ash holding ponds at a jointly owned coal-fired electric generating facility in Montana;
- replace all unprotected bare steel natural gas pipe in its service territory by 2015 as a result of a January 31, 2005 Washington Commission order; and
- 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 AROs to:

- dispose of treated wood poles;
- dispose of oil containing PCBs and the related equipment that held the oil;
- remove asbestos in facilities that have been identified for remodeling or demolition; and
- disconnect abandoned pipelines, purge the pipelines of natural gas and cut and cap their supplies of natural gas.

In 2006, the Company recognized an ARO for the decommissioning costs of the Frederickson facility at the end of its service life and costs related to wood poles, natural gas mains and contaminated oil in equipment placed in service in 2006. In 2007, the Company recognized an ARO related to a settlement agreement requiring the company to replace steel wrapped services categorized as being identified for replacement or priority replacements.

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

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2007	2006
Asset retirement obligation at beginning of year	$ 28,356	$ 28,274
Liability recognized in transition	--	--
New asset retirement obligation liability recognized in the period	1,733	487
Liability settled in the period	(1,597)	(1,351)
Accretion expense	1,116	946
Asset retirement obligation at December 31	$ 29,608	$ 28,356

The Company has identified the following obligations which were not recognized at December 31, 2007:

- a legal obligation under 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;
- an obligation under Washington state 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;
- 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;
- a legal obligation under the state of Washington environmental laws to remove and properly dispose of certain under and above ground storage fuel tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore

the liability cannot be reasonably estimated currently;

- a potential legal obligation, arising (if at all) upon the expiration of an existing FERC hydropower license, were FERC to then order project decommissioning. 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; and
- an obligation related to a special use permit for the Crystal Mountain generator site to remove certain structures, improvements and restore the site upon abandonment, termination, revocation or cancellation of the permit. The Company intends to renew its permit upon expiration and therefore, a liability 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, 2004 (rather than December 31, 2005) are as follows:

(DOLLARS IN THOUSANDS)	
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, 2004 (rather than December 31, 2005) is as follows:

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

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 $65.0, subject to adjustments. The Rights expire on December 21, 2010, unless redeemed or exchanged earlier by Puget Energy.

Immediately prior to the execution of the merger agreement announced on October 26, 2007, the Company and the Rights agent (Wells Fargo Bank, N.A.) entered into an amendment to the Rights agreement. The amendment provides that neither the execution of the merger agreement nor the execution of the stock purchase agreement (relating to the sale of 12.5 million shares of Puget Energy's common stock to certain members of the Consortium that closed on December 3, 2007), nor the consummation of the transactions contemplated by these agreements will trigger the provisions of the Rights agreement. The amendment also provides that the Rights shall expire at the effective time (as defined in the merger agreement), if the Rights have not otherwise terminated.

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 Restated 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 $481.5 million at December 31, 2007. For the years 2007, 2006 and 2005, the aggregate dividends per share declared by Puget Energy were $1.00, $1.00 and $1.00, respectively.

PSE paid cash dividends on its common stock to Puget Energy of $108.4 million, $109.8 million and $89.2 million for 2007, 2006 and 2005, respectively.

NOTE 7. *Redeemable Securities*

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, 2007, there were 25,689 shares of the 4.70% Series and 9,417 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 8.4%, 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 June 30, 2006, PSE called all of PSE's 8.4% 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). The Capital Trust II Securities were redeemed at par and dividends relating to the preferred securities were paid and included in interest expense. The Capital Trust Preferred Securities were redeemed using the proceeds of senior notes issued at an interest rate of 6.724%.

NOTE 8. *Long-Term Debt*

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

SERIES	DUE	2007	2006	SERIES	DUE	2007	2006
7.02%	2007	$ --	$ 20,000	5.197%	2015	$ 150,000	$ 150,000
7.04%	2007	--	5,000	7.35%	2015	10,000	10,000
7.75%	2007	--	100,000	7.36%	2015	2,000	2,000
3.363%	2008	150,000	150,000	6.74%	2018	200,000	200,000
6.51%	2008	1,000	1,000	9.57%	2020	25,000	25,000
6.53%	2008	3,500	3,500	7.15%	2025	15,000	15,000
7.61%	2008	25,000	25,000	7.20%	2025	2,000	2,000
6.46%	2009	150,000	150,000	7.02%	2027	300,000	300,000
6.61%	2009	3,000	3,000	7.00%	2029	100,000	100,000
6.62%	2009	5,000	5,000	5.483%	2035	250,000	250,000
7.12%	2010	7,000	7,000	6.724%	2036	250,000	250,000
7.96%	2010	225,000	225,000	6.274%	2037	300,000	300,000
7.69%	2011	260,000	260,000	6.974%	2067	250,000	--
6.83%	2013	3,000	3,000				
6.90%	2013	10,000	10,000				
				Total		$ 2,696,500	$ 2,571,500

On March 16, 2006, Puget Energy and PSE filed a shelf registration statement with the Securities and Exchange Commission for the offering of common stock, senior notes, preferred stock, and trust preferred securities of Puget Sound Energy Capital Trust III. The registration statement is valid for three years and does not specify the amount of securities that the Company may offer.

On June 30, 2006, PSE completed the issuance of $250.0 million of senior secured notes at a rate of 6.724%, which are due on June 15, 2036. The net proceeds from the issuance of the senior notes of approximately $247.8 million were used to redeem $200.0 million of 8.40% Capital Trust Preferred Securities, which were redeemed at par on June 30, 2006, and to repay a portion of PSE's short-term debt.

On September 18, 2006, PSE completed the issuance of $300.0 million of senior secured notes at a rate of 6.274%, which are due on March 15, 2037. The net proceeds from the issuance of the senior notes of approximately $297.4 million were used to repay PSE's outstanding short-term debt which was incurred primarily to fund construction programs.

On June 1, 2007, PSE redeemed the remaining 8.231% Capital Trust Preferred Securities (classified on the balance sheet as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities and referred to herein as Securities). The purpose of the redemption was to help reduce interest costs by retiring higher cost debt. The remaining $37.8 million of the Securities outstanding were redeemed on June 1, 2007 at a 4.12% premium, or $39.3 million, plus accrued interest on the redemption date.

On June 4, 2007, PSE issued $250.0 million of Junior Subordinated Notes (Notes) due June 2067. The Notes bear a fixed rate of interest for the first ten and a half years with interest payable semiannually in May and November of each year, after which the notes will bear a variable rate of interest (3-month LIBOR plus 2.35%). Proceeds were used to fund the redemption of the remaining $37.8 million 8.231% Securities and to repay short-term debt. The Notes are structured to be treated as debt by the Internal Revenue Service (IRS), yet they are considered to be similar to equity by the credit rating agencies. In addition, the Notes contain a call option feature and are callable in whole or in part by PSE on or after June 1, 2017. They are presented on the balance sheet as a separate line item in the redeemable securities and long-term debt.

Substantially all utility properties owned by the Company are subject to the lien of the Company's electric and natural 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, 2007, 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.

(DOLLARS IN THOUSANDS) AT DECEMBER 31 SERIES	DUE	2007	2006
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 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)	2008	2009	2010	2011	2013	THEREAFTER
Maturities of:						
Long-term debt	$ 179,500	$ 158,000	$ 232,000	$ 260,000	$ 13,000	$ 2,015,860

NOTE 9. *Related Party Transactions*

On June 1, 2006, PSE entered into a revolving credit facility with its parent, Puget Energy, in the form of a Demand Promissory Note (Note). Through the Note, PSE may borrow up to $30.0 million from Puget Energy, subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lowest of the weighted-average interest rate of (a) PSE's outstanding commercial paper interest rate; (b) PSE's senior unsecured revolving credit facility; or (c) the interest rate available under the receivable securitization facility of PSE Funding, Inc., a PSE subsidiary, which is the London Interbank Offered Rate (LIBOR) plus a marginal rate. At December 31, 2007 and 2006, the outstanding balance of the Note was $15.8 million and $24.3 million, respectively, and the interest rate was 5.31% and 5.54%, respectively. The outstanding balance and the related interest under the Note are eliminated by Puget Energy upon consolidation of PSE's financial statements. The $30.0 million credit facility with Puget Energy is unaffected by the pending merger.

During 2007, the Company purchased certain insurance policies from AEGIS and had two insurance claim receivables totaling $15.2 million due from AEGIS as of December 31, 2007. One nonemployee director of Puget Energy and PSE also serves on the board of AEGIS and a PSE management employee serves on one of AEGIS' risk management committees.

NOTE 10. *Liquidity Facilities and Other Financing Arrangements*

At December 31, 2007, PSE had borrowing arrangements that included a five-year $500.0 million unsecured credit agreement with a group of banks, a separate five-year $350.0 million unsecured credit agreement with the same group of banks, a five-year $200.0 million receivables securitization program and a $30.0 million demand promissory note with Puget Energy. These arrangements provide PSE with the ability to borrow at different interest rate options and include variable fee levels. Puget Energy has no bank credit facilities of its own.

The bank credit agreements allow the Company to make floating rate advances at either LIBOR plus a spread or the banks' prime rate and contain "credit sensitive" pricing with various spreads associated with different credit rating levels. Both bank credit agreements also allow for issuing standby letters of credit up to the entire amount of the credit agreement and can be used for commercial paper back-up. In March 2007, PSE amended the $500.0 million credit agreement to extend the expiration date from April 2011 to April 2012. This agreement is primarily used to backup PSE commercial paper sales.

There were no loans outstanding under the $500.0 million credit agreement at December 31, 2007.

The $350.0 million credit agreement was entered into in March 2007 and expires in April 2012. The agreement is intended to provide credit support for PSE's energy hedging activities. Costs of this hedging credit facility are recovered through the PCA and PGA mechanisms pursuant to an order of the Washington Commission. There were no loans outstanding under the $350.0 million credit agreement at December 31, 2007.

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. 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 $200.0 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. At December 31, 2007, PSE Funding had $152.0 million of loans secured by accounts receivable pledged as collateral. At December 31, 2006, PSE Funding had $110.0 million of loans secured by accounts receivable pledged as collateral.

The following table presents the liquidity facilities and other financing arrangements at December 31, 2007 and 2006.

(DOLLARS IN THOUSANDS) AT DECEMBER 31	2007	2006
Committed financing arrangements:		
PSE line of credit [1]	$ 500,000	$ 500,000
PSE hedging line of credit [2]	350,000	--
PSE receivables securitization program [3]	200,000	200,000
Uncommitted financing agreements:		
Puget Energy Demand Promissory Note [4]	30,000	30,000

1 *Provides liquidity support for PSE's outstanding commercial paper and letters of credit in the amount of $115.9 million in 2007 and $218.5 million in 2006, effectively reducing the available borrowing capacity under this credit line to $384.1 million and $281.5 million, respectively. There was $108.5 million of commercial paper outstanding at December 31, 2007, and $218.0 million outstanding at December 31, 2006.*

2 *Provides credit support for PSE's energy hedging activities. At December 31, 2007, there were no loans or outstanding letters of credit under this agreement.*

3 *Provides borrowings secured by accounts receivable and unbilled revenues. At December 31, 2007, PSE Funding had borrowed $152.0 million, leaving $48.0 million available to borrow under the program. At December 31, 2006, PSE Funding had $110.0 million of loans secured by accounts receivable pledged as collateral under the accounts receivable securitization program.*

4 *A demand promissory note with parent company, Puget Energy to borrow up to $30.0 million subject to approval by Puget Energy. At December 31, 2007 and 2006, the outstanding balance on the note was $15.8 million and $24.3 million, respectively. While reflected on PSE's balance sheet, the outstanding balance and related interest are eliminated on Puget Energy's balance sheet upon consolidation.*

NOTE 11. *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, 2007 and 2006.

(DOLLARS IN MILLIONS)	2007 CARRYING AMOUNT	2007 FAIR VALUE	2006 CARRYING AMOUNT	2006 FAIR VALUE
Financial assets:				
Cash	$ 40.8	$ 40.8	$ 28.1	$ 28.1
Restricted cash	4.8	4.8	0.8	0.8
Equity securities	1.5	1.5	2.0	2.0
Notes receivable and other	70.2	70.2	71.1	71.1
Energy derivatives	29.0	29.0	23.8	23.8
Long-term restricted cash	--	--	3.8	3.8
Financial liabilities:				
Short-term debt	$ 260.5	$ 260.5	$ 328.0	$ 328.0
Short-term debt owed by PSE to Puget Energy[1]	15.8	15.8	24.3	24.3
Preferred stock subject to mandatory redemption	1.9	1.2	1.9	1.3
Junior subordinated notes	250.0	215.1	--	--
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	--	--	37.8	43.2
Long-term debt – fixed-rate[2]	2,858.4	2,623.2	2,733.4	2,823.3
Energy derivatives	27.0	27.0	71.0	71.0

[1] *Short-term debt owed by PSE to Puget Energy is eliminated upon consolidation of Puget Energy.*
[2] *PSE's carrying value and fair value of fixed-rate long-term debt was the same as Puget Energy's debt in 2007 and 2006.*

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 12. *Leases*

The Company leases buildings and assets under operating leases. In October 2006, the Company entered into an agreement to purchase certain assets at the Whitehorn generating site, which historically had been leased under an operating lease. The purchase agreement resulted in the classification of the Whitehorn lease as a capital lease. In accordance with SFAS No. 71, the amortization of the leased asset has been modified so that total interest and amortization is equal to the rental expense allowed for rate-making purposes. Interest accretion for 2007 was $0.2 million and capital lease amortization was $0.6 million for 2007. Certain leases contain purchase options and renewal and escalation provisions. Rent expense net of sublease receipts were:

(DOLLARS IN THOUSANDS) AT DECEMBER 31	
2007	$ 27,012
2006	24,184
2005	17,145

Payments received for the subleases of properties were approximately $0.1 million, $0.1 million and $0.1 million for 2007, 2006 and 2005, respectively.

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

(DOLLARS IN THOUSANDS) AT DECEMBER 31	OPERATING	CAPITAL
2008	$ 14,921	$ 1,605
2009	14,569	23,453
2010	12,834	--
2011	13,306	--
2012	12,357	--
Thereafter	77,802	--
Total minimum lease payments	$ 145,789	$ 25,058

PSE leases a portion of its owned natural 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	2008	2009
Lease receipts	$ 1,182	$ 886

NOTE 13. *Income Taxes*

The details of income taxes on continuing operations are as follows:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2007	2006	2005
Charged to operating expense:			
Current:			
Federal	$3,238	$ 57,526	$142,004
State	(189)	979	1,936
Deferred - federal	69,966	34,485	(57,347)
Deferred investment tax credits	(433)	(503)	(553)
Total income taxes before cumulative effect of accounting change	72,582	92,487	86,040
Cumulative effect of accounting change	--	48	(38)
Total income taxes from continuing operations	$ 72,582	$ 92,535	$ 86,002

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2007	2006	2005
Charged to operating expense:			
Current:			
Federal	$ 5,555	$ 63,475	$ 142,772
State	(189)	979	2,705
Deferred - federal	69,248	34,738	(57,864)
Deferred investment tax credits	(433)	(503)	(553)
Total income taxes before cumulative effect of accounting change	74,181	98,689	87,060
Cumulative effect of accounting change	--	48	(38)
Total income taxes from continuing operations	$ 74,181	$ 98,737	$ 87,022

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)	2007	2006	2005
Income taxes at the statutory rate	$ 89,966	$ 90,947	$ 81,275
Increase (decrease):			
Utility plant differences	6,032	9,307	9,534
AFUDC excluded from taxable income	(5,055)	(7,987)	(4,536)
Capitalized interest	3,649	5,806	3,026
Production tax credit	(20,154)	(7,019)	(564)
Other - net	(1,856)	1,481	(2,733)
Total income taxes	$ 72,582	$ 92,535	$ 86,002
Effective tax rate	28.2%	35.6%	37.0%

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2007	2006	2005
Income taxes at the statutory rate	$ 92,858	$ 96,417	$ 81,827
Increase (decrease):			
Utility plant differences	6,032	9,307	9,534
AFUDC excluded from taxable income	(5,055)	(7,987)	(4,536)
Capitalized interest	3,649	5,806	3,026
Production tax credit	(20,154)	(7,019)	(564)
Other - net	(3,149)	2,213	(2,265)
Total income taxes	$ 74,181	$ 98,737	$ 87,022
Effective tax rate	28.0%	35.8%	37.2%

The Company's deferred tax liability at December 31, 2007 and 2006 is composed of amounts related to the following types of temporary differences:

PUGET ENERGY (DOLLARS IN THOUSANDS)	2007	2006
Utility plant and equipment	$ 717,661	$ 643,885
Regulatory asset for income taxes	104,928	115,305
Storm damage	44,571	35,408
Other deferred tax liabilities	62,395	38,256
Subtotal deferred tax liabilities	929,555	832,854
Contributions in aid of construction	(75,492)	(58,038)
Other deferred tax assets	(39,913)	(30,896)
Subtotal deferred tax assets	(115,405)	(88,934)
Total	$ 814,150	$ 743,920

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2007	2006
Utility plant and equipment	$ 717,661	$ 643,885
Regulatory asset for income taxes	104,928	115,305
Storm damage	44,571	35,408
Other deferred tax liabilities	65,616	42,195
Subtotal deferred tax liabilities	932,776	836,793
Contributions in aid of construction	(75,492)	(58,038)
Other deferred tax assets	(39,913)	(30,897)
Subtotal deferred tax assets	(115,405)	(88,935)
Total	$ 817,371	$ 747,858

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

PUGET ENERGY (DOLLARS IN THOUSANDS)	2007	2006
Current deferred taxes	$ (4,011)	$ (1,175)
Non-current deferred taxes	818,161	745,095
Total	$ 814,150	$ 743,920

PUGET SOUND ENERGY (DOLLARS IN THOUSANDS)	2007	2006
Current deferred taxes	$ (4,011)	$ (1,175)
Non-current deferred taxes	821,382	749,033
Total	$ 817,371	$ 747,858

The Company calculates its deferred tax assets and liabilities under SFAS No. 109. 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. For ratemaking purposes, deferred taxes are not provided for certain temporary differences. PSE has established a regulatory asset for income taxes recoverable through future rates related to those temporary differences for which no deferred taxes have been provided, based on prior and expected future ratemaking treatment.

IRS AUDIT

As a matter of course, the Company's tax returns are routinely audited by federal, state and city tax authorities. In May 2006, the IRS completed its examination of the company's 2001, 2002 and 2003 federal income tax returns. The Company formally appealed the IRS audit adjustment relating to the Company's accounting method with respect to capitalized internal labor and overheads. In its 2001 tax return, PSE claimed a deduction when it changed its tax accounting method with respect to capitalized internal labor and overheads. Under the new method, the Company could immediately deduct certain costs that it had previously capitalized. In the audit, the IRS disallowed the deduction.

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 did not impact earnings but did have a cash flow impact of $33.2 million in the fourth quarter 2005 and $33.1 million in 2006. As of December 31, 2006, the full tax benefit had been repaid.

During 2007, the IRS national office established settlement guidelines which the appeals office will use in reaching settlements with taxpayers. The effect of the settlement guidelines shift some of the benefits claimed in 2001 through 2004 into 2005 and 2006. As a result, in 2007 the Company has accrued interest in the amount of $5.5 million.

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 Washington Commission had reduced PSE's ratebase by $72.0 million in its order of February 18, 2005. The accounting petition was approved by the Washington 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. The Washington Commission granted cost recovery of these deferred carrying costs over two years, beginning January 13, 2007. In addition, it is management's expectation that the Company could request rate recovery of the regulatory asset for the interest accrued.

In its 2003 tax return, the Company claimed a deduction for a portion of the California Independent System Operator (CAISO) receivable. Upon examination, the IRS claimed that the deduction was not valid for the 2003 tax year. The Company formally appealed. In appeals, the Company and the IRS agreed to move the deduction from 2003 to 2005. In the fourth quarter 2007, the Company recorded interest expense in the amount of $2.2 million to reflect the transfer of the deduction from 2003 to 2005.

Accounting for Uncertainty in Income Taxes

In July 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109" (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with FASB Statement No. 109, "Accounting for Income Taxes." FIN 48 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50% likelihood of being sustained.

FIN 48 was effective for the Company as of January 1, 2007. As of the date of adoption, the Company had no material unrecognized tax benefits. As of December 31, 2007, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

For federal income tax purposes, the Company has open tax years from 2001 through 2007. The Company continues its policy of classifying interest as interest expense and penalties as other expense in the financial statements.

NOTE 14. *Retirement Benefits*

On September 29, 2006, FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158). SFAS No. 158 is effective for fiscal years ending after December 15, 2006, which is the year ended December 31, 2006 for the Company. SFAS No. 158 was adopted prospectively as required by the statement. SFAS No. 158 requires the Company to report the overfunded or underfunded status of defined benefit postretirement plans in the Company's consolidated balance sheet. An overfunded status would result in the recognition of an asset and an underfunded status would result in the recognition of a liability. This amount is to be measured as the difference between the fair value of plan assets and the projected benefit obligation. The following table illustrates the effect of applying SFAS No. 158 in 2006, the year of initial adoption by the Company.

	Before Application of Statement 158		Adjustments		After Application of Statement 158	
(Dollars in Thousands)	Pension Plan	Other Benefits	Pension Plan	Other Benefits	Pension Plan	Other Benefits
Transition Adjustments for Statement of Financial Position:						
Prepaid benefit cost	$ 122,274	$ --	$ (122,274)	$ --	$ --	$ --
Accrued benefit (liability)	(33,056)	(12,309)	33,056	12,309	--	--
Intangible asset	4,027	--	(4,027)	--	--	--
Accumulated other comprehensive income, (pre-tax)	6,789	--	29,647	(950)	36,436	(950)
Noncurrent asset	--	--	101,708	--	101,708	--
Current liability	--	--	(4,533)	(50)	(4,533)	(50)
Noncurrent liability	--	--	(33,577)	(11,309)	(33,577)	(11,309)
Total	$ 100,034	$ (12,309)	$ --	$ --	$ 100,034	$ (12,309)

The Company has a defined benefit pension plan covering substantially all PSE employees, with a cash balance feature for all but IBEW 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.

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)	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 469,010	$ 454,519	$ 27,207	$ 26,251
Service cost	13,311	12,554	269	361
Interest cost	26,513	24,668	1,249	1,522
Mergers, sales and closures	--	--	(2,648)	--
Amendment[1]	--	--	(306)	--
Actuarial loss (gain)	(16,621)	4,774	(3,723)	1,261
Benefits paid	(28,849)	(27,505)	(3,184)	(2,189)
Benefit obligation at end of year	$ 463,364	$ 469,010	$ 18,864	$ 27,206

1 *The Company has an amendment related to changes in eligibility criteria. On June 20, 2007, the International Brotherhood of Electrical Workers (IBEW) ratified a collective bargaining agreement with PSE. The collective bargaining agreement included changes to the Company's subsidy for retiree medical insurance. Effective June 20, 2007, IBEW-represented employees hired after June 20, 2002 will not receive a retiree medical subsidy at retirement.*

(DOLLARS IN THOUSANDS)	Pension Benefits 2007	2006	Other Benefits 2007	2006
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 532,608	$ 481,444	$ 15,847	$ 15,668
Actual return on plan assets	52,444	75,278	499	1,699
Employer contribution	2,326	3,391	1,538	669
Benefits paid	(28,849)	(27,505)	(3,184)	(2,189)
Fair value of plan assets at end of year	$ 558,529	$ 532,608	$ 14,700	$ 15,847
Funded status at end of year	$ 95,165	$ 63,598	$ (4,164)	$ (11,359)

(DOLLARS IN THOUSANDS)	Pension Benefits 2007	2006	Other Benefits 2007	2006
Amounts recognized in Statement of Financial Position consist of:				
Noncurrent assets	$ 132,276	$ 101,708	$ --	$ --
Current liabilities	(4,029)	(4,533)	(49)	(50)
Noncurrent liabilities	(33,082)	(33,577)	(4,115)	(11,309)
Total	$ 95,165	$ 63,598	$ (4,164)	$ (11,359)
Amounts recognized in Accumulated Other Comprehensive Income consist of:				
Net loss (gain)	$ (5,407)	$ 29,984	$ (8,445)	$ (6,341)
Prior service cost (credit)	4,409	6,452	433	2,862
Transition obligations (assets)	--	--	250	2,529
Total	$ (998)	$ 36,436	$ (7,762)	$ (950)

The projected benefit obligation, fair value of plan assets and the funded status, measured as the difference between the fair value of plan assets and the benefit obligation for the qualified pension plan were $426.3 million, $558.5 and $132.3 million, respectively, as of December 31, 2007. For the non-qualified pension plan, the projected benefit obligation, fair value of plan assets and the funded status were $37.1 million, $0.0 million and $(37.1) million, respectively, as of December 31, 2007.

The projected benefit obligation, fair value of plan assets and the funded status, measured as the difference between the fair value of plan assets and the benefit obligation for the qualified pension plan were $430.9 million, $532.6 million and $101.7 million, respectively, as of December 31, 2006. For the non-qualified pension plan, the projected benefit obligation, fair value of plan assets and the funded status were $38.1 million, $0.0, and $(38.1) million, respectively, as of December 31, 2006.

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2007	2006	2005	OTHER BENEFITS 2007	2006	2005
Components of net periodic benefit cost:						
Service cost	$ 13,311	$ 12,553	$ 11,549	$ 269	$ 361	$ 305
Interest cost	26,513	24,667	23,855	1,250	1,522	1,409
Expected return on plan assets	(38,859)	(37,572)	(37,928)	(826)	(871)	(878)
Amortization of prior service cost	2,041	2,341	2,867	353	534	466
Amortization of net loss (gain)	5,187	5,230	3,354	(834)	(273)	(612)
Amortization of transition (asset) obligation	--	--	(163)	234	418	418
Net periodic benefit cost (income)	$ 8,193	$ 7,219	$ 3,534	$ 446	$ 1,691	$ 1,108
Curtailment/settlement cost [1]	$ --	$ --	$ --	$ 708	$ --	$ --

[1] *As part of the June 20, 2007 settlement, IBEW-represented employees with less than five years of service would no longer receive a medical subsidy at retirement and those employees with more than one year of service but less than five years of service received a one-time cash payment. Current IBEW-represented employees with five or more years of service had a one-time opportunity to elect a cash payment that varied depending on the years of employment with PSE in lieu of continuing eligibility for the retiree medical subsidy. As a result of the termination, the curtailment loss was $0.7 million.*

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2007	PENSION BENEFITS 2006	OTHER BENEFITS 2007	OTHER BENEFITS 2006
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:				
(Increase) decrease during year under SFAS 132R	$ --	$ (497)	$ --	$ --
(Increase) decrease due to adoption of SFAS 158	--	29,647	--	(950)
Net loss (gain)	(30,205)	--	(3,396)	--
Amortization of net loss (gain)	(5,187)	--	835	--
Mergers, sales and closures	--	--	(3,356)	--
Prior service cost (credit)	--	--	(307)	--
Amortization of prior service cost	(2,042)	--	(353)	--
Amortization of transition (asset) obligation	--	--	(234)	--
Total change in other comprehensive income for year	$ (37,434)	$ 29,150	$ (6,811)	$ (950)

The estimated net loss (gain) and prior service cost (credit) for the pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2008 are $0.7 million and $1.3 million, respectively. The estimated net loss (gain), prior service cost (credit) and transition obligation (asset) for the other postretirement plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2008 are $(0.8) million, less than $0.1 million and less than $0.1 million, respectively.

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

BENEFIT OBLIGATION ASSUMPTIONS	PENSION BENEFITS 2007	PENSION BENEFITS 2006	PENSION BENEFITS 2005	OTHER BENEFITS 2007	OTHER BENEFITS 2006	OTHER BENEFITS 2005
Discount rate	6.30%	5.80%	5.60%	6.30%	5.80%	5.60%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	9.00%	10.00%	11.00%

BENEFIT COST ASSUMPTIONS	PENSION BENEFITS 2007	PENSION BENEFITS 2006	PENSION BENEFITS 2005	OTHER BENEFITS 2007	OTHER BENEFITS 2006	OTHER BENEFITS 2005
Discount Rate	5.80%	5.60%	5.60%	5.80%	5.60%	5.60%
Return on plan assets	8.25%	8.25%	8.25%	3.9-8%	4.3-8%	4.3-8%
Rate of compensation increase	4.50%	4.50%	4.50%	--	--	--
Medical trend rate	--	--	--	10.00%	11.00%	12.00%

The assumed medical inflation rate used to determine benefit obligations is 9.0% in 2008 grading down to 7.0% in 2010. A 1.0% change in the assumed medical inflation rate would have the following effects:

(DOLLARS IN THOUSANDS)	2007 1% INCREASE	2007 1% DECREASE	2006 1% INCREASE	2006 1% DECREASE
Effect on post-retirement benefit obligation	$ 216	$ (189)	$ 752	$ (666)
Effect on service and interest cost components	16	(15)	42	(38)

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 Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is as follows. The market-related value of assets is based on a five-year smoothing of asset gains/losses measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

The discount rate was determined by using market interest rate data and the 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.

The aggregate expected contributions by the Company to fund the pension and other benefit plans for the year ending December 31, 2008 are $4.0 million and less than $0.1 million, respectively. The full amount of the pension funding for 2008 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:

	2007		2006	
	Pension Benefits	Other Benefits	Pension Benefits	Other Benefits
Short-term investments and cash	2.08%	--	2.7%	--
Equity securities	54.83%	--	62.9%	--
Fixed income securities	15.07%	12.3%	14.8%	13.4%
Mutual funds (equity and fixed income)	28.02%	87.7%	19.6%	86.6%

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 are as follows:

(Dollars in Thousands)	2008	2009	2010	2011	2012	2013-2017
Total benefits	$33,103	$31,953	$35,230	$35,278	$37,536	$201,308

The Company has a Retirement Plan 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 Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets 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 Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Equity securities	35%	62%	85%
Fund of Hedge Funds	5%	10%	15%
Tactical Asset Allocation	--	5%	10%
Fixed-income securities	15%	23%	30%
Real estate and cash	--	--	15%

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.

NOTE 15. *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 $9.0 million, $7.9 million and $6.9 million for the years 2007, 2006 and 2005, respectively. The Employee Investment Plan eligibility requirements are set forth in the plan documents.

NOTE 16. *Stock-based Compensation Plans*

Prior to 2006, the Company had various stock-based compensation plans which were accounted for according to APB No. 25, and related interpretations as allowed by SFAS No. 123. 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. The Company applied SFAS No. 123 accounting to stock compensation awards granted subsequent to January 1, 2003, while grants prior to 2003 continued to be accounted for using the intrinsic value method of APB No. 25. Effective January 1, 2006, the Company adopted the fair value recognition provisions of SFAS No. 123R, using the modified-prospective transition method. Under that transition method, compensation cost recognized effective 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123 and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. Results for prior periods have not been restated, as provided for under the modified-prospective method.

The adoption of SFAS No. 123R resulted in a cumulative benefit from an accounting change of $0.1 million, net of tax, for the quarter ended March 31, 2006. The cumulative effect adjustment is the result of the inclusion of estimated forfeitures occurring before award vesting dates in the computation of compensation expense for unvested awards. For purposes of determining stock compensation expense under SFAS No. 123R, forfeitures for multi-year plans are calculated based on the historical average forfeiture rate for vested cycles and are trued up to actual forfeiture experience in the year of vesting.

As a result of adopting SFAS No. 123R on January 1, 2006, the Company's income before income taxes and net income from continuing operations at December 31, 2006, was $0.1 million and $0.1 million higher, respectively, than if it had continued to account for share-based compensation under SFAS No. 123 due to the inclusion of estimated forfeitures in compensation cost.

The Company's Long-Term Incentive Plan (LTI Plan), established in 1995 after approval by shareholders, 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. The 2006 and 2007 cycles included a grant of restricted stock, which was added to reduce the volatility of the plan. Beginning with the 2004 share grants, plan participants meeting the Company's stock ownership guidelines can elect to be paid up to 50.0% of the share award in cash. The maximum number of shares that may be purchased or issued as new shares for the LTI Plan is 4,200,000.

PERFORMANCE SHARE GRANTS

The Company generally awards performance share grants annually under the LTI Plan. These are granted to key employees and vest at the end of three years for grants made in 2004, 2005, 2006 and 2007. Grants made in 2003 vest over a four year period. The number of shares awarded and expense recorded depends 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 $2.3 million, $(1.6) million and $1.0 million for 2007, 2006 and 2005, respectively. As of December 31, 2007, $2.8 million of total unrecognized compensation cost, net of forfeitures, related to nonvested performance share grants. That cost is expected to be recognized over a weighted-average period of 1.6 years. The weighted-average fair value per performance share granted for the years ended 2006 and 2005 was $24.77 and $21.19, respectively.

Performance shares activity for the twelve months ended December 31, 2007 was as follows:

	Number of Shares	Weighted-Average Fair Value Per Share
Performance Shares Outstanding at December 31, 2005 includes:	907,983	$ 20.11
Granted	152,254	22.52
Vested	(40,852)	19.74
Cancelled*	(572,392)	19.81
Forfeited	(68,782)	19.30
Total at December 31, 2006:	378,211	$ 21.72
Granted	144,894	24.64
Vested	(232,344)	21.21
Cancelled	(59)	22.52
Forfeited	(5,583)	22.73
Performance Shares Outstanding at December 31, 2007:	285,119	$ 23.60

* *Performance Shares at December 31, 2006 were cancelled because performance modifiers were not achieved.*

Plan participants meeting the Company's stock ownership guidelines can elect to be paid up to 50.0% of the share award in cash. The portion of the performance share grants that can be paid in cash is classified and accounted for as a liability. As a result, the compensation expense of these liability awards is recognized over the performance period based on the fair value (i.e. cash value) of the award, and is periodically updated based on expected ultimate cash payout. Compensation cost recognized during the performance period for the liability portion of the performance grants is based on the closing price of the Company's common stock on the date of measurement and the number of months of service rendered during the period. The equity portion is valued at the closing price of the Company's common stock on the grant date.

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 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 annually 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 ten years from the grant date and have a remaining contractual term of approximately six years. All 300,000 options are fully vested and remained outstanding and exercisable at December 31, 2007. The fair value of the options at the grant date was $3.33 per share. Compensation expense related to stock options was $0.0 for each of 2007, 2006 and 2005, respectively. The total fair value of stock options vested during 2007 and 2006 was $0.1 and $0.2 million, respectively. The fair value of the stock option award was estimated on the date of grant using the Black-Scholes option valuation model.

RESTRICTED STOCK

In 2007, 2006, 2005, 2004 and 2003, the Company granted 97,244 shares, 107,555 shares, 50,000 shares, 40,000 shares and 11,000 shares, respectively, of restricted stock under the LTI Plan to be purchased on the open market or as a new issuance. Under the 2007 and 2006 grants, the shares vest 15.0% in year 1 on January 1, 25.0% vest in year 2 on January 1, and the remaining 60.0% vest in year 3 on January 1, based upon a performance and service condition. Under the 2005 grant, 40,000 shares vest in one installment on May 6, 2008 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. For the 2003 grant, 1,000 vested in 2003 with the remaining shares vesting evenly over the following five years.

Restricted stock activity for the twelve months ended December 31, 2007 was as follows:

	Number of Shares	Weighted-Average Fair Value Per Share
Restricted Stock Outstanding at December 31, 2005:	116,000	$ 22.72
Granted	107,555	21.32
Vested	(15,333)	22.56
Forfeited	(2,566)	21.35
Restricted Stock Outstanding at December 31, 2006:	205,656	$ 22.02
Granted	97,244	24.72
Vested	(39,083)	22.27
Forfeited	(3,435)	23.19
Restricted Stock Outstanding at December 31, 2007:	260,382	$ 22.98

There was $2.0 million of total unrecognized compensation cost related to nonvested restricted stock at December 31, 2007. That cost is expected to be recognized over a weighted-average period of 1.9 years. Compensation expense related to the restricted shares was $3.0 million and $2.0 million for 2007 and 2006, respectively. Dividends are paid on all outstanding shares of restricted stock and are accounted for as a Puget Energy common stock dividend, not as compensation expense. During 2007, 39,083 shares of restricted stock vested and 3,435 shares of restricted stock were forfeited. During 2006, 15,333 shares of restricted stock vested and 2,566 shares of restricted stock were forfeited. During 2005, 12,000 shares of restricted stock vested and no restricted stock was forfeited during 2005. The weighted-average fair value per restricted share vested for the year ended 2005 was $22.85. The fair value of restricted shares vested during 2007, 2006 and 2005 was $0.9 million, $0.3 million and $0.3 million, respectively. The fair value of the restricted stock is based on the closing price of the Company's common stock on the date of grant.

RESTRICTED STOCK UNITS

In 2004, the Company granted 10,000 restricted stock units outside of the LTI Plan but subject to the terms and conditions of the plan. 2,000 shares vested on January 8, 2007, 3,000 shares vested on January 8, 2008 and the remaining 5,000 shares will vest on May 6, 2008.

Restricted stock units activity for the twelve months ended December 31, 2007 was as follows:

	Number of Shares	Weighted-Average Fair Value Per Share
Restricted Stock Units Outstanding at December 31, 2005:	10,000	$ 25.36
Granted	--	--
Vested	--	--
Restricted Stock Units Outstanding at December 31, 2006:	10,000	$ 25.36
Granted	--	--
Vested	2,000	25.36
Restricted Stock Units Outstanding at December 31, 2007:	8,000	$ 25.36

There was $0.01 million of total unrecognized compensation cost related to nonvested restricted stock units as of December 31, 2007. That cost is expected to be recognized on May 6, 2008. There were no restricted stock units granted or forfeited during 2007 and 2006. The restricted stock units will be settled in cash when they become vested at the end of each cycle. 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 for 2007 and 2006. The fair value of the restricted stock units is based on the closing price of the Company's common stock at each reporting period.

RETIREMENT EQUIVALENT STOCK

The Company has a retirement equivalent stock agreement under 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. Retirement equivalent stock activity is as follows:

	Number of Shares	Weighted-Average Fair Value Per Share
Retirement Equivalent Stock Awarded:		
2003	4,319	$ 22.05
2004	6,469	$ 23.77
2005	6,063	$ 24.70
2006	8,218	$ 20.42
2007	9,476	$ 25.36

The shares vest over a period from January 1, 2002 to May 2008 at 15.0% per year for the first six years and the remaining 10.0% in the seventh year. At December 31, 2007, there were 8,636 total shares of nonvested retirement equivalent stock units with a weighted-average grant date fair value of $23.36. There was $0.1 million unrecognized compensation cost related to nonvested retirement equivalent stock units as of December 31, 2007. That cost is expected to be recognized over a weighted-average period of one year. The equivalent value of dividends is paid on the accumulated retirement equivalent stock units and added to the deferred compensation account. Compensation expense related to the retirement equivalent stock agreement was $0.1 million, $0.2 million and $0.1 million in 2007, 2006 and 2005, respectively. During 2007, 12,288 retirement equivalent stock units vested. The fair value of the restricted stock is based on the closing price of the Company's common stock on the date of grant.

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 85.0% of the lower of the stock's fair market price at the beginning or the end of the six-month period. A maximum of 1,000,000 shares may be sold to employees under the plan. At December 31, 2007, 554,277 shares could still be sold to employees under the plan. In 2007 and 2006, 66,819 and 66,496 shares were issued for the ESPP, respectively. Under SFAS No. 123 accounting that the Company adopted in 2003 and under SFAS No. 123R, the ESPP is considered to be compensatory and the amount is immaterial to the financial statements. Dividends are not paid on ESPP shares until they are purchased by employees and thus are accounted for as dividends, not compensation expense. Cash received from the exercise of the ESPP during 2007 was $1.4 million. The Company suspended further offerings in the ESPP pending the outcome of the merger effective with the offering period beginning January 1, 2008.

NON-EMPLOYEE DIRECTOR STOCK PLAN

The Company has a director stock plan for all non-employee directors of Puget Energy and PSE. An amended and restated plan was approved by shareholders in 2005. Under the plan, which has a term through December 31, 2015, non-employee directors receive a portion of their quarterly retainer fees in Puget Energy stock except that 100.0% 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 choose to continue to receive their entire retainer in Puget Energy stock. The compensation expense related to the director stock plan was $0.6 million and $0.5 million in 2007 and 2006, respectively. 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, 2007, 53,173 shares had been issued or purchased for the director stock plan and 101,678 deferred, for a total of 154,851 shares. As of December 31, 2006, the number of shares that had been purchased for the director stock plan was 34,166 and deferred was 92,807, for a total of 126,973 shares.

OPTION MODEL ASSUMPTIONS

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 outstanding in 2007 and 2006.

STOCK ISSUANCE CYCLE	2007	2006	2005	2004	2003	2002
Stock options						
Risk-free interest rate	*	*	*	*	*	4.32%
Expected lives – years	*	*	*	*	*	4.5
Expected stock volatility	*	*	*	*	*	23.62%
Dividend yield	*	*	*	*	*	5.00%
Performance awards						
Risk-free interest rate	**	**	2.50%	2.59%	2.35%	*
Expected lives – years	3.0	3.0	3.0	3.0	4.0	*
Expected stock volatility	**	**	15.10%	22.24%	23.85%	*
Dividend yield	*	*	4.18%	4.45%	4.86%	*
Employee Stock Purchase Plan						
Risk-free interest rate	4.79%	4.96%	2.68%	1.28%	1.07%	*
Expected lives – years	0.5	0.5	0.5	0.5	0.5	*
Expected stock volatility	12.24%	9.79%	13.98%	9.89%	19.47%	*
Dividend yield	4.04%	4.55%	4.17%	4.42%	4.39%	*

* *Not applicable*

** *Fair value is determined by end of period market value.*

The expected lives of the securities represent the estimated period of time until exercise and are based on the vesting period of the award and the historical exercise experience of similar awards. All participants were assumed to have similar exercise behavior. Expected volatility is based on historical volatility over the approximate expected term of the option.

NOTE 17. *Accounting for Derivative Instruments and Hedging Activities*

SFAS No. 133 as amended, requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value. The Company enters into 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 provided they meet certain criteria. Generally, NPNS applies if PSE deems the counterparty creditworthy, if the counterparty owns or controls energy resources within the western region to allow for physical delivery of the energy and if the transaction is within PSE's forecasted load requirements and adjusted from time to time. 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 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 electric generation resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy risk 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 realizing 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 natural gas portfolios.

The following table are electric derivatives that are designated as cash flow hedges or contracts that do not meet Normal Purchase Normal Sale (NPNS) at December 31, 2007 and December 31, 2006:

(Dollars in Millions)	Electric Derivatives December 31, 2007	Electric Derivatives December 31, 2006
Short-term asset	$ 11.1	$ 10.1
Long-term asset	6.6	6.8
Total assets	$ 17.7	$ 16.9
Short-term liability	$ 9.8	$ 9.0
Long-term liability	--	0.4
Total liabilities	$ 9.8	$ 9.4

If it is determined that it is uneconomical to operate PSE's controlled electric generating facilities in the future period, the fuel supply cash flow hedge relationship is terminated and the hedge is de-designated which results in the unrealized gains and losses associated with the contracts being recorded in the income statement. As these contracts are settled, the costs are recognized as energy costs and are included as part of the PCA mechanism.

At December 31, 2007, the Company had an unrealized day one loss deferral of $9.0 million related to a three year locational power exchange contract which was modeled and therefore the day one gain was deferred under EITF No. 02-3. The deferred loss is being amortized over the term of the contracts. Any future changes in the mark-to-market value will be recorded through the income statement. The contracts have economic benefit to the Company over their terms. The locational exchange will help ease electric transmission congestion across the Cascade Mountains during the winter months as PSE will take delivery of energy at a location that interconnects with PSE's transmission system in Western Washington. At the same time, PSE will make available the quantities of power at the Mid-Columbia trading hub location.

The following table presents the impact of changes in the market value of derivative instruments not meeting NPNS or cash flow hedge criteria to the Company's earnings during the twelve months ending December 31, 2007 and December 31, 2006:

(Dollars in millions)	2007	2006	Change
Increase (decrease) in earnings	$ 2.7	$(0.1)	$ 2.8

The amount of unrealized gain, net of tax, related to the Company's energy-related cash flow hedges under SFAS No. 133 consisted of the following at December 31, 2007 and December 31, 2006:

(Dollars in Millions, net of tax)	December 31, 2007	December 31, 2006
Other comprehensive income – unrealized gain	$ 3.4	$ 4.9

The following table are derivative hedges of natural gas contracts to serve natural gas customers at December 31, 2007:

(Dollars in millions)	Gas Derivatives December 31, 2007	December 31, 2006
Short-term asset	$ 6.0	$ 6.7
Long-term asset	5.3	0.1
Total assets	$ 11.3	$ 6.8
Short-term liability	$ 17.3	$ 61.6
Total liabilities	$ 17.3	$ 61.6

At December 31, 2007, the Company had total assets of $11.3 million and total liabilities of $17.3 million related to hedges of natural gas contracts to serve natural gas customers. 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 hedges are realized in future periods, they will be recorded as natural gas costs under the PGA mechanism.

NOTE 18. *Colstrip Matters*

In May 2003, approximately 50 plaintiffs brought an action against the owners of Colstrip which has since been amended to add additional claims. The lawsuit alleges that certain domestic water wells, groundwater and the Colstrip water supply pond were contaminated by seepage from a Colstrip Units 1 & 2 effluent holding pond, that seepage from Colstrip Units 1 & 2 have decreased property values and that seepage from the Colstrip water supply pond caused structural damage to buildings and toxic mold. Plaintiffs are seeking compensatory and punitive damages. Discovery is ongoing and trial is scheduled for June 2008.

On March 29, 2007, a second complaint related to pond seepage was filed on behalf of two ranch owners alleging damage due to the Colstrip Units 3 & 4 effluent holding pond. Discovery is on going and no trial date has been set.

On May 18, 2005, the Environmental Protection Agency (EPA) enacted the Clean Air Mercury Rule (CAMR) that will permanently cap and reduce mercury emissions from coal-fired power plants. The Montana Board of Environmental Review approved a more stringent rule to limit mercury emissions from coal-fired plants on October 16, 2006 (0.9 lbs/TBtu, instead of the federal 1.4 lbs/TBtu). The Colstrip owners are still evaluating the potential impact of the new Montana rule and it is still unknown whether the new rule will be appealed. Treatment technology studies undertaken by the Colstrip owners estimate that PSE's portion of the costs to comply with the Montana rule could be as much as $11.0 million in construction expenditures and as much as $9.0 million per year in operation and maintenance expenditures but this number could change as new information becomes available. On February 8, 2008, the District of Columbia Federal Court of Appeals vacated the EPA CAMR rule. This action does not invalidate the rule adopted by Montana.

On June 15, 2005, the U. S. Environmental Protection Agency (EPA) issued the Clean Air Visibility Rule to address regional haze or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units, including presumptive limits for sulfur dioxide, particulate matter and nitrogen oxide controls for large units. In February 2007, Colstrip was notified by EPA that Colstrip Units 1 & 2 were determined to be subject to the BART requirements, PSE submitted a BART engineering analysis for Colstrip Units 1 & 2 in August 2007. PSE cannot yet determine the need for or costs of additional controls to comply with this rule.

NOTE 19. *Taxes Other Than Income Taxes*

(DOLLARS IN THOUSANDS)	2007	2006	2005
Taxes other than income taxes:			
Real estate and personal property	$ 49,873	$ 39,832	$ 44,472
State business	118,954	107,140	93,893
Municipal and occupational	111,241	97,671	85,154
Other	35,836	33,144	30,841
Total taxes other than income taxes	$ 315,904	$ 277,787	$ 254,360
Charged to:			
Operating expense	$ 288,417	$ 255,712	$ 233,742
Other accounts, including construction work in progress	27,487	22,075	20,618
Total taxes other than income taxes	$ 315,904	$ 277,787	$ 254,360

NOTE 20. *Regulation and Rates*

ELECTRIC REGULATION AND RATES

STORM DAMAGE DEFERRAL ACCOUNTING

On February 18, 2005, the Washington Commission issued a general rate case order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $7.0 million annually may be deferred for qualifying storm damage costs that meet the IEEE outage criteria for system average interruption duration index. PSE's storm accounting, which allows deferral of certain storm damage costs, was subject to review by the Washington Commission at the end of the current three-year period, which was December 31, 2007. PSE filed an accounting petition with the Washington Commission to extend the current deferral mechanism beyond December 31, 2007 and this was approved by the Washington Commission on November 6, 2007. Deferral of future storm damage costs will be determined in PSE's electric general rate case which is expected to conclude in November 2008. In 2007, PSE incurred $38.3 million in storm-related electric transmission and distribution system restoration costs, of which $29.3 million was deferred for future recovery in electric rates. In 2006, PSE incurred $103.2 million in storm-related electric transmission and distribution system restoration costs, of which $92.3 million was deferred.

ELECTRIC GENERAL RATE CASE

On December 3, 2007, PSE filed a general rate case with the Washington Commission which proposed an increase in electric rates of $174.5 million or 9.5% annually, effective November 3, 2008. PSE requested a weighted cost of capital of 8.6%, or 7.29% after-tax, and a capital structure that included 45.0% common equity with a return on equity of 10.8%. An order from the Washington Commission is expected in October 2008.

On January 5, 2007, the Washington Commission issued its order in PSE's electric general rate case filed in February 2006, approving a general rate decrease for electric customers of $22.8 million or 1.3% annually. The rates for electric customers are effective beginning January 13, 2007. In its order, the Washington Commission approved a weighted cost of capital of 8.4%, or 7.06% after-tax, and a capital structure that included 44.0% common equity with a return on equity of 10.4%. The Washington Commission had earlier approved (on June 28, 2006) a power cost only rate case (PCORC) increase of $96.1 million annually effective July 1, 2006.

POWER COST ONLY RATE CASE

PCORC, a limited-scope proceeding, was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the PCORC proceeding also provides for timely review of new resource acquisitions costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission approved an expedited five-month PCORC decision timeline rather than the statutory 11-month timeline for a general rate case.

On March 20, 2007, PSE submitted a Power Cost Only Rate Case (PCORC) filing to request approval of an updated power cost baseline rate beginning September 2007. The PCORC filing also requested recovery of ownership and operating costs of the Goldendale generating facility (Goldendale) through retail electric rates. On May 23, 2007, PSE filed updated power costs due to changes in market conditions of natural gas and other costs which resulted in a revised proposed increase of $77.8 million or 4.4% annually. On July 5, 2007, a settlement agreement in this PCORC signed by PSE and certain other parties to the proceeding was filed with the Washington Commission, the terms of which included an electric rate increase of $64.7 million. On August 2, 2007, the Washington Commission approved the settlement agreement and authorized an increase in PSE's electric rates of $64.7 million or an average increase of 3.7% annually effective September 1, 2007. The investment in Goldendale was found prudent, thus allowing for recovery of certain ownership and operating costs through electric retail rates effective September 1, 2007 along with updating other power costs.

In accordance with the August 2, 2007 Washington Commission order approving the PCORC settlement, PSE and other parties agreed to conduct a collaborative stakeholder review of the PCORC process to consider the scope and timing of the PCORC mechanism. The collaborative review included but was not limited to: 1) the number of PCORCs that a company will be allowed to file in any given year; 2) the number and timing of updates that a company may submit in the PCORC process; 3) the items directly associated with power costs that may be included and considered in a PCORC filing; and 4) whether the number and timing of updates may vary depending on if other parties can easily verify. On December 12, 2007 the collaboration filed a final report with the Commission reporting that the parties were not able to reach agreement on revisions to the PCORC mechanism and that the parties will address such issues in the Company's pending general rate case filing.

On April 11, 2007, the Washington Commission approved PSE's petition for issuance of an accounting order that authorizes PSE to defer certain ownership and operating costs (and associated carrying costs) the Company incurred related to its purchase of Goldendale during the period prior to inclusion in PSE's retail electric rates in the PCORC. The deferral is for the time period from March 15, 2007 through September 1, 2007. As of December 31, 2007, PSE had established a regulatory asset of $11.5 million including carrying costs. PSE anticipates amortization of the costs will begin no later than November 2008 as determined in PSE's next general rate case.

RESIDENTIAL EXCHANGE DEFERRED ASSET

On May 21, 2007, the Bonneville Power Administration (BPA) notified PSE and other investor-owned utilities that BPA was suspending payments related to its residential exchange program due to adverse Ninth Circuit Court of Appeals (Ninth Circuit) decisions of May 3, 2007. The Ninth Circuit concluded in its decisions that certain BPA actions in entering into residential exchange settlements in 2000 were not in accordance with the law. BPA suspended payments under the residential exchange program as a result of the Ninth Circuit decisions. As a result of the BPA suspension of payment, PSE filed revisions to the tariffs which pass through the benefits of the Residential Exchange to all residential and small farm customers. The Washington Commission approved the termination of the Residential Exchange Credit effective June 7, 2007. Under Federal law, investor-owned utilities receiving residential exchange benefits must pass-through the benefits to their residential and small farm electric customers.

On August 29, 2007, the Washington Commission approved PSE's accounting petition to defer as a regulatory asset the excess BPA Residential Exchange benefit provided to customers and accrue monthly carrying charges on the deferred balance from June 7, 2007 until the deferral is recovered from customers or BPA. The accounting petition sought approval to record carrying costs on the deferred balance until the deferred balance is recovered from customers. As of December 31, 2007, PSE has recorded a regulatory asset of $35.7 million. On December 17, 2007, BPA released a proposal for public comment which would provide temporary, interim relief to the region's investor-owned utilities until final Residential Exchange Program (REP) contracts are reached and executed which are planned to go into effect October 1, 2008 or 2009. These interim agreements are offered in exchange for suspension of certain litigation activities, and will be trued-up to the actual final REP benefits for each individual company as established in BPA's upcoming administrative proceedings.

Following the close of the comment period on January 7, 2008, BPA will review all comments received and issue a record of decision on whether to offer the proposed interim agreements to customers. If BPA decides to offer the agreements, they could be sent to the utilities for signature in February or March 2008. BPA is proposing to provide these interim benefits in one lump-sum payment, and have said that utilities could receive their interim payments as soon as five to ten working days after signing agreements.

NATURAL GAS SYSTEM RECORDKEEPING COMPLAINT

In May 2007, the Washington Commission Staff alleged that PSE's natural gas system service provider had violated certain Washington Commission recordkeeping rules. The Washington Commission has since filed a complaint against PSE that includes Washington Commission Staff's recommendation that PSE be assessed a $2.0 million regulatory penalty. As of June 30, 2007, PSE management determined the penalty met the SFAS No. 5 criteria for recording a loss contingency and recorded a $2.0 million loss reserve. The Washington Commission investigation is ongoing.

PRODUCTION TAX CREDIT

On October 30, 2006, PSE revised its PTC electric tariff to increase the revenue credit to customers from $13.1 million to $28.8 million, effective January 1, 2007. On December 12, 2007, PSE revised its PTC electric tariff to decrease the revenue credit to customers from $28.8 million to $28.6 million, effective January 12, 2008. The credit is based on expected wind generation and reflects the true-up of prior years' credits provided to customers versus credits for actual wind generation taken for federal income taxes and the addition of Wild Horse to the wind portfolio. PSE will be revising its tariff effective January 1, 2009 based on actual PTC results for 2008 and project 2009 PTCs based on a filing to be made in the fourth quarter 2008.

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 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 was limited to $40.0 million plus 1.0% of the excess. In October 2005, the Washington Commission approved a shift to an annual PCA measurement period from January through December starting in 2007. On January 5, 2007, the Washington Commission approved the continuation of the PCA mechanism under the same annual graduated scale without a cumulative cap for excess power costs. All significant variable power supply cost variables (hydroelectric and wind generation, market price for purchased power and surplus power, natural gas and coal fuel price, generation unit forced outage risk and transmission cost) are included in the PCA mechanism.

The PCA mechanism apportions increases or decreases in power costs, on a calendar year basis, between PSE and its customers on a graduated scale:

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 allowed for a reduction to 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 $40.0 million plus 1.0% of the excess. Power cost variation after December 31, 2006 will be apportioned on a calendar year basis, without a cumulative cap.*

ACCOUNTING ORDERS

On April 26, 2006, the Washington Commission approved an accounting petition on a temporary basis to defer an $89.0 million one-time capacity reservation charge along with accrual of interest at the authorized after-tax rate of return. As part of the general rate case order of January 5, 2007, the Washington Commission approved the regulatory accounting treatment that had been approved in the accounting petition. The payment was made in relation to an agreement for the purchase of power from Chelan County PUD (Chelan). PSE and Chelan have entered into an agreement which provides for the purchase of 25% of the output of Chelan's Rock Island (622 megawatts (MW)) and Rocky Reach (1,237 MW) dams on the Columbia River. The agreement called for PSE to make a one-time payment of $89.0 million on April 27, 2006. Then, upon the expiration of the existing contracts in 2011, PSE will begin purchasing 25% of the output at the projects' costs for the next 20 years.

GAS REGULATION AND RATES

GAS GENERAL RATE CASE

On December 3, 2007, PSE filed a general rate case with the Washington Commission which proposed an increase in natural gas rates of $56.8 million or 5.3% annually, effective November 3, 2008. PSE requested a weighted cost of capital of 8.6%, or 7.29% after-tax, and a capital structure that included 45.0% common equity with a return on equity of 10.8%. An order from the Washington Commission is expected in October 2008.

On January 5, 2007, the Washington Commission issued its order in PSE's natural gas general rate case, granting an increase for natural gas customers of $29.5 million or 2.8% annually, effective beginning January 13, 2007 which resulted in an increase in gas margin of approximately 9.8% annually. In its order the Washington Commission approved the same weighted cost of capital of 8.4% or 7.06% after-tax and capital structure that included 44.0% common equity with a return on equity of 10.4%, consistent with the Company's electric operations.

PURCHASED GAS ADJUSTMENT

PSE has a Purchased Gas Adjustment (PGA) mechanism in retail natural gas rates to recover variations in gas supply and transportation costs. Variations in gas rates are passed through to customers, therefore PSE's gas margin and net income are not affected by such variations. On September 26, 2007, the Washington Commission approved PSE's requested revisions to its PGA tariffs resulting in a rate decrease for gas customers of $148.1 million or 13.0% annually effective October 1, 2007. The rate decrease was the result of lower costs of natural gas in the forward market and a refund of the accumulated PGA payable balance over a 12-month period beginning October 1, 2007. The PGA rate change will decrease PSE's revenue but will not impact the Company's natural gas margins or net income as the decreased revenue will be offset by decreased purchased gas costs and decreased revenue sensitive taxes.

The following rate adjustments were approved by the Washington Commission in relation to the PGA mechanism during 2007, 2006 and 2005:

EFFECTIVE DATE	PERCENTAGE INCREASE (DECREASE) IN RATES	ANNUAL INCREASE (DECREASE) IN REVENUES (DOLLARS IN MILLIONS)
October 1, 2007	(13.0) %	$ (148.1)
October 1, 2006	10.2 %	95.1
October 1, 2005	14.7 %	121.6

NOTE 21. *Other*

The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage natural 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 $7.8 million, $9.0 million and $4.1 million in 2007, 2006 and 2005, 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 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, 2006, the White River project net book value totaled $72.5 million, which included $41.9 million of net utility plant, $17.3 million of capitalized FERC licensing costs, $6.7 million of costs related to construction work in progress and $6.6 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 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 for the Company. 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). 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.

One of these counterparties, Sumas Cogeneration Company, L.P. (Sumas), delivered a letter to PSE on May 7, 2007, stating that it had sold its dedicated natural gas reserves to a third party and that it no longer intended to deliver energy to PSE through the remaining term of the contract, which expires on April 15, 2013. The last energy delivered to PSE by Sumas occurred on March 15, 2007. Following negotiations with Sumas on December 7, 2007, PSE and Sumas signed a Membership Interest Purchase and Sale Agreement for the acquisition of the 125 MW power plant located in Sumas, Washington. Sumas also agreed to transfer an undivided ownership interest in the pipeline easements to PSE. PSE expects the transaction to close in the second half of 2008, after it receives approval from FERC and presidential permits to operate the natural gas pipeline.

For the two remaining 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 2007, 2006 and 2005 for these three entities was $216.5 million, $259.8 million and $267.0 million, respectively.

On May 30, 2007, PSE agreed to extend the terms of the existing leases of its Bellevue corporate office complex from ten years to 15 years. PSE's lease agreement included a one-time right to purchase the office complex. PSE elected to monetize the value of this purchase option and negotiated for a cash payment of $18.9 million, net of transaction fees, in exchange for the termination of the purchase option. PSE has filed an accounting petition with the Washington Commission seeking deferred accounting treatment of the net proceeds and amortization of the net proceeds to match the near-term contractual lease payment increases. The Washington Commission has not yet ruled on this matter.

As of December 31, 2007, PSE had $25.1 million in insurance receivables recorded related to two property damage claims and a general liability claim. As of February 28, 2008, PSE has received $6.9 million in payments from the insurers associated with these claims. Of the remaining receivable balance, $7.6 million remains in review by the associated insurance companies and any amount not recovered would be expensed in the period that it is deemed nonrecoverable. An additional $10.1 million of the receivable balance represents an estimate based on the cost that would have been incurred to repair, rather than replace, the damaged parts. If PSE does not receive full recovery of this receivable, the accrued amount will be recorded to utility plant.

In a decision issued in October 2007, the Washington State Supreme Court ruled that certain job reporting practices involving the use of company vehicles are compensable time under Washington State's wage and hour laws. One union representing a portion of PSE's workforce claims its members should now be compensated for PSE job site reporting practices as a result of this decision. The extent of the claims and financial impact on PSE currently is unknown.

In November 2007, PSE was audited by the Western Electricity Coordinating Council (WECC) under delegated authority of the NERC, the FERC-certified Electric Reliability Organization (ERO). Previously PSE had submitted several self reports and mitigation plans to WECC for review and approval. The WECC audit team told PSE of four additional preliminary alleged violations (without any specified penalties) that were not previously self reported. In response, PSE submitted self reports and mitigation plans for the four violations. WECC has accepted the self reports and mitigation plans. The ultimate result of the audit, including the nature or amount of any penalties, cannot be predicted at this time.

NOTE 22. *Commitments and Contingencies*

For the year ended December 31, 2007, approximately 22.8% of the Company's energy output was obtained at an average cost of approximately $0.015 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, 2007, 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 12/31/07[2] (Millions)	Company's Annual Amount Purchasable (Approximate): % of Output	Megawatt Capacity	Cost[3] (Millions)
Rock Island						
Original units	2012	2029	$ 134.5	50.0	248	$ 34.0
Additional units	2012	2029	323.9	50.0		
Rocky Reach [8]	2011	2006	373.9	38.9	488	29.1
Wells	2018	2012	197.8	29.9	251	11.4
Priest Rapids [4,5,6]	TBD[7]	TBD[7]	257.2	4.3	39	12.4
Wanapum [4,5,6]	2009	TBD[7]	432.5	10.8	106	5.4
Total			$ 1,719.8		1,132	$ 92.3

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: 81.4% at Rock Island; 66.9% at Rocky Reach; and 30.6% 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 2007 costs associated with the interest portion of debt service are: Rock Island, $12.4 million for all units; Rocky Reach, $8.2 million; Wells, $3.0 million; Priest Rapids, $0.5 million; and Wanapum, $2.1 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. In June 2007, Grant County PUD and the Yakama Nation reached a settlement agreement which requires the PUD to make a declining block of Priest Rapids Project Power, or its financial equivalent, available to the Yakama Nation throughout the terms of the New FERC license. In exchange for this consideration, the Yakama Nation would dismiss their requests for onerous relicensing terms and conditions. The Company will be paying its pro rata share of the cost of the Yakama Nation settlement agreement which will be included in annual power costs of the Priest Rapids Project.*

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.)*

8 *On February 3, 2006, PSE and Chelan entered into a new Power Sales Agreement and a related Transmission Agreement for 25.0% 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 25.0% of the operating costs of the facilities. 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 have been approved by both FERC and the Washington Commission.*

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)	2008	2009	2010	2011	2012	2013 & THERE-AFTER	TOTAL
Columbia River projects	$ 104.3	$ 101.2	$ 98.3	$ 121.2	$ 95.5	$ 1,622.6	$ 2,143.1
Other utilities	101.0	176.1	172.9	125.2	114.6	417.5	1,107.3
Non-utility generators	206.2	195.1	197.1	201.4	--	--	799.8
Total	$ 411.5	$ 472.4	$ 468.3	$ 447.8	$ 210.1	$ 2,040.1	$ 4,050.2

Total purchased power contracts provided the Company with approximately 9.4 million, 9.6 million, and 9.6 million megawatt hours (MWh) of firm energy at a cost of approximately $390.6 million, $421.7 million and $419.7 million for the years 2007, 2006, and 2005, respectively.

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 (one million British thermal units, equal to one Dth) 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 natural gas is reflective of the daily price of natural gas at the United States/Canada border near Sumas, Washington. PSE has entered into financial arrangements to hedge future natural gas supply costs associated with this obligation. The Company has a maximum financial obligation under hedge agreements of $27.7 million in 2008. The Company has obligations for natural gas supply amounting to $8.4 million in 2008 for the Tenaska plant.

As part of its electric operations and in connection with the 1999 buyout of the Cabot natural 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 natural 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 $4.7 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 natural gas supply agreements that comprise 40% of the plant's requirements with remaining terms ranging of less than one year. The obligation under this contract is $11.1 million in 2008. The Company has other natural gas-fired generation facility obligations for natural gas supply amounting to $19.5 million in 2008.

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 $242.9 million, $64.1 million and $4.6 million in 2008, 2009, and 2010 respectively.

NATURAL GAS SUPPLY

The Company has also entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its firm customers. Many of these contracts, which have remaining terms from less than one year to 20 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company contracts for all of its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation. The Company incurred demand charges in 2007 for firm natural gas supply, firm transportation service and firm storage and peaking service of $1.8 million, $116.2 million and $9.3 million, respectively. WNG CAP I, a PSE subsidiary, incurred demand charges in 2007 for firm transportation service of $4.3 million, which is included in the total Company demand charges. The Company incurred demand charges in 2007 for firm transportation service for the natural gas supply for its combustion turbines in the amount of $13.5 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)	2008	2009	2010	2011	2012	2013 & THERE-AFTER	TOTAL
Firm natural gas supply	$ 1.0	$ 0.5	$ 0.5	$ 0.5	$ 0.0	$ --	$ 2.5
Firm transportation service	115.3	114.9	105.2	84.8	83.8	331.9	835.9
Firm storage service	9.2	9.1	8.2	7.8	7.7	13.8	55.8
Total	$ 125.5	$ 124.5	$ 113.9	$ 93.1	$ 91.5	$ 345.7	$ 894.2

SERVICE CONTRACTS

On August 30, 2001, PSE and Alliance Data Systems Corp. (Alliance Data) signed a contract under which Alliance Data will provide data processing and billing services for PSE. The obligations under the contract are $23.7 million in 2008, $24.3 million in 2009, $25.0 million in 2010 and $17.0 million in 2011.

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 factored 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 is $6.5 million in 2008, $1.3 million in 2009, $1.2 million in 2010, $2.1 million in 2011, $1.4 million in 2012 and $12.5 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), pursuant to which Vestas will operate, maintain, service and remedy any defects or deficiencies in the constructed wind turbine generators (WTGs) at Hopkins Ridge and their associated equipment on PSE's behalf. Vestas 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 was approximately $2.6 million in 2007 and will escalate on each January 1 during the term by the Consumer Price Index.

In September 2005, in connection with its purchase of the Wild Horse wind power project, PSE entered into a Service & Maintenance Agreement and a Warranty Agreement (the Agreements) 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 WTGs at Wild Horse and their associated equipment on PSE's behalf. Vestas American also provides certain warranties in relation to the availability performance of the Wild Horse project. The Agreements provide for a five-year term continuing until November 2011. The annual fee was approximately $5.5 million in 2007 and will escalate each January 1 thereafter during the term by the Gross Domestic Product Implicit Price Deflator (GDPIPD).

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, 2007, PSE's outstanding balance under the lease was $48.3 million. The expected residual value under the lease is the lesser of $37.4 million or 60.0% 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 87.0% of the unamortized value of the equipment.

SURETY BOND

The Company has a self-insurance surety bond in the amount of $10.1 million guaranteeing compliance with the Industrial Insurance Act (workers' compensation) and ten self-insurer's pension bonds totaling $1.4 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 (EPA), the Washington State Department of Ecology (Ecology) and/or other third parties as potentially responsible at several contaminated sites and manufactured natural 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 relevant sites. 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, subject to Washington Commission review. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. At December 31, 2007, the Company had $1.9 million and $35.9 million in deferred electric and natural gas environmental costs, respectively.

In November 2006, PSE's Crystal Mountain Generation Station had an accidental release of approximately 18,000 gallons of diesel fuel. PSE crews and consultants responded and worked with applicable state and federal agencies to control and remove the spilled diesel. On July 11, 2007, PSE received a Notice of Completion for work performed pursuant to the Administrative Order for Removal from the EPA. The Notice stated that PSE had met the requirements of the Order and the accompanying scope of work. Total removal costs as of December 31, 2007 were approximately $14.0 million. PSE estimates the total remediation cost to be approximately $15.0 million, which has been accrued or paid. At December 31, 2007, PSE had an insurance receivable recorded in the amount of $12.6 million associated with this fuel release. PSE received a partial payment of $5.0 million on this receivable in January 2008. PSE has also responded to a request for information under the Clean Water Act from the EPA. On February 13, 2008, the Department of Justice issued a letter to PSE seeking civil penalties pursuant to the Clean Water Act on behalf of EPA and offering to discuss settlement of these claims as well as, natural resource damage claims related to the diesel spill. PSE plans to enter into such discussions with EPA. The Company believes its loss reserve is sufficient.

NOTE 23. *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 was sold on May 7, 2006 and is not considered a reportable segment. See Note 3 for InfrastruX summarized financial information and discussion of discontinued operations.

2007 (DOLLARS IN THOUSANDS)	REGULATED UTILITY	OTHER	RECONCILING ITEM	PUGET ENERGY TOTAL
Revenues	$ 3,207,061	$ 13,086	$ --	$ 3,220,147
Depreciation and amortization	279,014	208	--	279,222
Income tax	70,794	1,788	--	72,582
Operating income	439,433	1,601	--	441,034
Interest charges, net of AFUDC	205,209		--	205,209
Net income from continuing operations	184,049	627	--	184,676
Total assets	7,513,884	84,852	--	7,598,736
Construction expenditures - excluding equity AFUDC	737,258	--	--	737,258

2006 (Dollars in Thousands)	Regulated Utility	Other	Reconciling Item	Puget Energy Total
Revenues	$ 2,899,234	$ 7,829	$ --	$ 2,907,063
Depreciation and amortization	262,129	212	--	262,341
Income tax	96,727	(4,240)	--	92,487
Operating income	416,734	4,117	--	420,851
Interest charges, net of AFUDC	168,139	--	--	168,139
Net income from continuing operations	172,644	(5,420)	--	167,224
Total assets	6,993,131	72,908	--	7,066,039
Construction expenditures - excluding equity AFUDC	749,516	--	--	749,516

2005 (Dollars in Thousands)	Regulated Utility	Other	Reconciling Item	Puget Energy Total
Revenues	$ 2,570,182	$ 7,826	$ --	$ 2,578,008
Depreciation and amortization	241,385	249	--	241,634
Income tax	85,169	871	--	86,040
Operating income	385,816	4,481	--	390,297
Interest charges, net of AFUDC	164,965	224	--	165,189
Net income from continuing operations	228,030	4,293	--	232,323
Total assets[1]	6,267,012	68,392	274,547	6,609,951
Construction expenditures - excluding equity AFUDC	568,381	--	--	568,381

1 *Reconciling item consists of assets of InfrastruX which is presented as discontinued operations.*

NOTE 24. *Agreement and Plan of Merger*

On October 26, 2007, Puget Energy announced that it had entered into a definitive Agreement and Plan of Merger, dated as of October 25, 2007, pursuant to which Puget Energy will be acquired by a consortium of long-term infrastructure investors led by Macquarie Infrastructure Partners, the Canada Pension Plan Investment Board and British Columbia Investment Management Corporation, and also includes Alberta Investment Management, Macquarie-FSS Infrastructure Trust and Macquarie Capital Group Limited (collectively, the Consortium). At the effective time of the merger, each issued and outstanding share of common stock of Puget Energy, other than any shares in respect of which dissenter's rights are perfected and other than any shares owned by the Consortium, shall be cancelled and shall be converted automatically into the right to receive $30.00 in cash, without interest.

The consummation of the merger is subject to the satisfaction or waiver of certain closing conditions, including the approval of the transaction by the affirmative vote of two-thirds of the votes entitled to be cast thereon by Puget Energy's shareholders, the termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the HSR Act) and the receipt of required regulatory approvals. On December 17, 2007, PSE and the Consortium filed a joint application seeking approval of the merger with the Washington Utilities and Transportation Commission (Washington Commission). A decision by the Washington Commission is expected on September 2, 2008. If approved, closing is expected to occur during the fourth quarter 2008. On January 29, 2008, PSE and the Consortium filed an application with FERC seeking approval of the proposed merger pursuant to section 203 of the Federal Power Act. A decision by FERC is expected by May 29, 2008.

The merger agreement contains termination rights for both Puget Energy and the Consortium under certain circumstances. In the event Puget Energy elects to terminate the merger agreement under specified circumstances, it would be required to pay to the acquiring entity either $30.0 million if the termination is based on the submission of an alternative proposal meeting certain requirements by a party with whom Puget Energy had been in discussions prior to December 10, 2007, or $40.0 million if such fee becomes payable in all other circumstances, plus, in each case, documented out-of-pocket expenses of the Consortium of up to $10.0 million. In addition, Puget Energy may be required to pay the Consortium documented out-of-pocket expenses incurred by the Consortium not in excess of $15.0 million if the merger agreement is terminated due to a breach of the terms of the Merger Agreement by Puget Energy and such breach is incurable or has not been cured within a specified time. The acquiring entity may be required to pay Puget Energy an amount equal to $130.0 million if the merger agreement is terminated due to a breach of the terms of the merger agreement by the acquiring entity and such breach is incurable or has not been cured within a specified time.

NOTE 25. *Litigation*

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

The following discussion summarizes the status as of the date of this report of ongoing proceedings relating to the western power markets to which PSE is a party. PSE is vigorously defending each of these cases. 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.

California Receivable and California Refund Proceeding. Since 2001, PSE has held a receivable relating to unpaid bills for power that PSE sold in 2000 into the markets maintained by the CAISO. At December 31, 2007, the net receivable for such sales was approximately $21.1 million. PSE's ability to recover all or a portion of this amount is uncertain. At this time there is no reasonable basis under applicable financial accounting rules to adjust PSE's net receivable because the outcome of further court and FERC actions is uncertain and any likely financial impact cannot be quantified.

In 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). FERC also ordered that if the refunds required by the formula it adopted would cause a seller to recover less than its actual costs for the refund period, the seller is allowed to document its costs and limit its refund liability commensurately. Consistent with those orders, PSE filed a fuel cost adjustment claim and a portfolio cost claim. Recovery of those amounts is uncertain, but the amount owed to PSE under all FERC orders to date is included in the PSE net receivable amount. FERC has not issued a final order determining "who owes how much to whom" in the California Refund Proceeding and it is not clear when such an order will be issued.

In the course of the California Refund Proceeding, FERC has issued dozens of orders. Most have been taken up on appeal before the Ninth Circuit, which has issued opinions on some issues in the last several years. These cases are described below in the section, "California Litigation."

California Litigation. *Lockyer v. FERC.* 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. This case was originally presented to FERC upon complaint that the adoption and implementation of market rate authority was flawed. FERC dismissed the complaint after all sellers refiled summaries of transactions with California entities during 2000 and 2001. 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 remands to FERC the question of whether to allow refunds. On December 28, 2006, PSE and several other energy sellers filed a petition for a writ of certiorari to the U.S. Supreme Court, but the petition was not granted and the matter was remanded to FERC for further proceedings on December 4, 2007. 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.

CPUC v. FERC. On August 2, 2006, the Ninth Circuit decided that FERC erred in excluding potential relief for tariff violations for periods that pre-dated October 2, 2000 and additionally ruled that FERC should consider remedies for transactions previously considered outside the scope of the proceedings. The August 2, 2006 decision may adversely impact PSE's ability to recover the full amount of its CAISO receivable. The decision may also expose PSE to claims or liabilities for transactions outside the previously defined "refund period." At this time the ultimate financial outcome for PSE is unclear. Rehearing by the Ninth Circuit on this matter was sought on November 16, 2007. The rehearing petition has not been acted upon. In addition, parties have been engaged in court-sponsored settlement discussions, and those discussions may result in some settlements. PSE is unable to predict either the outcome of the proceedings or the ultimate financial effect on PSE.

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 investigated 26 entities that allegedly had potential "partnerships" with Enron. PSE was not named in that show cause order. On January 22, 2004, FERC stated that it did not intend to proceed further against other parties.

The second show cause order 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 a nominal amount to settle all claims. FERC approved the settlement on January 22, 2004. The California parties filed for rehearing of that order. On March 17, 2004, PSE moved to dismiss the California parties' rehearing request and awaits FERC action on that motion.

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 ordered for the California markets. FERC dismissed PSE's complaint, but PSE challenged that dismissal. On June 19, 2001, FERC ordered price caps on energy sales throughout the West. Various parties, including the Port of Seattle and the cities of Seattle and Tacoma, then moved to intervene in the proceeding seeking retroactive refunds for numerous transactions. The proceeding became known as the "Pacific Northwest Refund Proceeding," though refund claims were outside the scope of the original complaint. On June 25, 2003, FERC terminated the proceeding on procedural, jurisdictional and equitable grounds and on November 10, 2003, FERC on rehearing, confirmed the order terminating the proceeding. On August 24, 2007, the Ninth Circuit issued a decision concluding that FERC should have evaluated and considered evidence of market manipulation in California and its potential impact in the Pacific Northwest. It also decided that FERC should have considered purchases made by the California Energy Resources Scheduler and/or the California Department of Water Resources in the Pacific Northwest Proceeding. On December 17, 2007, PSE and Powerex separately filed requests for rehearing with the Ninth Circuit of this decision. Those requests remain pending. PSE intends to vigorously defend its position in this proceeding, but it is unable to predict the outcome of this matter.

Wah Chang Suit. In June 2004, Wah Chang, an Oregon company, filed suit in federal court against Puget Energy and PSE, among others. The complaint is similar to the allegations made in other cases that were dismissed as having no merit. The case was 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 Ninth Circuit. Oral argument took place on April 10, 2007 and the Ninth Circuit issued an opinion affirming the lower court's dismissal of the case on November 20, 2007. Wah Chang filed a petition for rehearing; on January 15, 2008, the Ninth Circuit denied rehearing.

PROCEEDING RELATING TO THE PROPOSED MERGER

On October 26, 2007 and November 2, 2007, two separate lawsuits were filed against the Company and all of the members of the Company's Board of Directors in Superior Court in King County, Washington. The lawsuits, respectively, are entitled, *Tansey v. Puget Energy, Inc., et al.*, Case No. 07-2-34315-6 SEA and *Alaska Ironworkers Pension Trust v. Puget Energy, Inc., et al.*, Case No. 07-2-35346-1 SEA. The lawsuits are both denominated as class actions purportedly on behalf of Puget Energy's shareholders and assert substantially similar allegations and causes of action relating to the proposed merger. (See Note 24 for more information regarding the proposed transaction.) The complaints allege that Puget Energy's directors breached their fiduciary duties in connection with the merger and seek virtually identical relief, including an order enjoining the consummation of the merger. Pursuant to court order dated November 26, 2007, the two cases were consolidated for all purposes and entitled *In re Puget Energy, Inc. Shareholder Litigation*, Case No. 07-2-34315-6 SEA.

On February 6, 2008, the parties entered into a memorandum of understanding providing for the settlement of the consolidated lawsuit, subject to customary conditions including completion of appropriate settlement documentation, confirmatory discovery and court approval. Pursuant to the memorandum of understanding, the Company has agreed to include certain additional disclosures in its proxy statement relating to the merger. The Company does not admit, however, that its prior disclosures were in any way materially misleading or inadequate. In addition, the Company and the other defendants in the consolidated lawsuit deny the plaintiffs' allegations of wrongdoing and violation of law in connection with the merger. The settlement, if completed and approved by the court, will result in dismissal with prejudice and release of all claims of the plaintiffs and settlement class of the Company's shareholders that were or could have been brought on behalf of the plaintiffs and the settlement class. In connection with such settlement, the plaintiffs intend to seek a court-approved award of attorneys' fees and expenses in an amount up to $290,000, which the Company has agreed to pay.

PROCEEDINGS RELATED TO BONNEVILLE POWER ADMINISTRATION

Petitioners in several actions in the Ninth Circuit against BPA asserted that BPA acted contrary to law in entering into or performing or implementing a number of agreements, including the amended settlement agreement (and the May 2004 agreement) between BPA and PSE regarding the BPA Residential Exchange Program. BPA rates used in such agreements between BPA and PSE for determining the amounts of money to be paid to PSE by BPA under such agreements during the period October 1, 2001 through September 30, 2006 have been confirmed, approved and allowed to go into effect by FERC. Petitioners in several actions in the Ninth Circuit against BPA also asserted that BPA acted contrary to law in adopting or implementing the rates upon which the benefits received or to be received from BPA during the October 1, 2001 through September 30, 2006 period were based. The parties to these various actions presented oral arguments to the Ninth Circuit in November 2005. A number of parties have claimed that the BPA rates proposed or adopted in the BPA rate proceeding to develop BPA rates to be used in the agreements for determining the amounts of money to be paid to PSE by BPA during the period October 1, 2006 through September 30, 2009 are contrary to law and that BPA acted contrary to law or without authority in deciding to enter into, or in entering into or performing or implementing such agreements. In August 2007, BPA requested FERC to continue a stay of FERC's review of such rates in light of uncertainties created by the Ninth Circuit litigation.

On May 3, 2007, the Ninth Circuit issued an opinion in *Portland Gen. Elec. v. BPA*, No. 01-70003, in which proceeding the actions of BPA in entering into settlement agreements regarding the BPA Residential Exchange Program with PSE and with other investor-owned utilities were challenged. In this opinion, the Ninth Circuit granted petitions for review and held the settlement agreements entered into between BPA and the investor-owned utilities being challenged in that proceeding to be inconsistent with statute. On May 3, 2007, the Ninth Circuit also issued an opinion in *Golden Northwest Aluminum v. BPA*, No. 03-73426, in which proceeding the petitioners sought review of BPA's 2002-06 power rates. In this opinion, the Ninth Circuit granted petitions for review and held that BPA unlawfully shifted onto its preference customers the costs of its settlements with the investor-owned utilities. On October 5, 2007, petitions for rehearing of these two opinions were denied. On February 1, 2008, PSE and other utilities filed in the Supreme Court of the United States a petition for a writ of certiorari to review the decisions of the Ninth Circuit.

In May 2007, following the Ninth Circuit's issuance of these two opinions, BPA suspended payments to PSE under the amended settlement agreement (and the May 2004 agreement). On August 29, 2007, the Washington Commission approved PSE's accounting petition to defer as a regulatory asset the excess BPA Residential Exchange benefit provided to customers and accrue monthly carrying charges on the deferred balance from June 7, 2007 until the deferral is recovered from customers or BPA. As of December 31, 2007, PSE has a regulatory asset of $35.7 million. On October 11, 2007, the Ninth Circuit remanded the May 2004 agreement to BPA in light of the *Portland Gen. Elec. V. BPA* opinion and dismissed the remaining three pending cases regarding settlement agreements. On February 8, 2008, BPA issued a notice commencing a rate proceeding to respond to the various Ninth Circuit opinions. In the notice, BPA proposed to adjust its Fiscal Year 2009 rates and to determine the amounts of Residential Exchange benefits paid since 2002 that may be recovered. BPA is proposing to determine an amount that was improperly passed through to residential and small farm customers of PSE and the other regional investor-owned utilities during the 2002 to 2008 rate period and recovering this amount over time by reducing future benefits under the Residential Exchange Program. The amount to be recovered over future periods from PSE's residential and small farm customers in BPA's initial proposal is $150.4 million. However, this is a initial proposal and is subject to BPA's rate case process resulting in a final decision in approximately July. It is not clear what impact, if any, development or review of such rates, review of such agreements and the above described Ninth Circuit litigation may ultimately have on PSE.

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) 2007 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 1,003,904	$ 661,138	$ 601,680	$ 953,425
Operating income	158,060	102,048	54,488	126,438
Net income before cumulative effect of accounting change	79,061	38,612	11,394	55,397
Net income	79,061	38,612	11,394	55,397
Basic earnings per common share	$ 0.68	$ 0.33	$ 0.10	$ 0.46
Diluted earnings per common share	$ 0.68	$ 0.33	$ 0.10	$ 0.45

(Unaudited; dollars in thousands except per share amounts) 2006 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 878,148	$ 574,391	$ 519,541	$ 934,983
Operating income	153,586	81,893	60,114	125,258
Net income before cumulative effect of accounting change	92,520	53,529	15,922	57,156
Net income	92,609	53,529	15,922	57,156
Basic earnings per common share	$ 0.80	$ 0.46	$ 0.14	$ 0.49
Diluted earnings per common share	$ 0.79	$ 0.46	$ 0.14	$ 0.49

PUGET SOUND ENERGY

(Unaudited; dollars in thousands) 2007 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 1,003,904	$ 661,138	$ 601,680	$ 953,425
Operating income	158,223	102,207	55,611	134,343
Net income before cumulative effect of accounting change	78,777	38,357	12,046	61,947
Net income	78,777	38,357	12,046	61,947

(Unaudited; dollars in thousands) 2006 QUARTER	FIRST	SECOND	THIRD	FOURTH
Operating revenues	$ 878,148	$ 574,391	$ 519,541	$ 934,983
Operating income	154,121	82,340	60,365	125,856
Net income before cumulative effect of accounting change	73,750	30,100	15,632	57,169
Net income	73,839	30,100	15,632	57,169

SCHEDULE I

Condensed Financial Information of Puget Energy

Puget Energy Condensed Statements of

INCOME

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

FOR YEARS ENDED DECEMBER 31	2007	2006	2005
Equity in earnings of subsidiary	$ 191,127	$ 177,585	$ 146,769
Other operations and maintenance	(1,206)	(1,830)	(1,354)
Merger related cost	(8,143)	--	--
Other income (deductions):			
Charitable foundation contributions	--	(15,000)	--
Interest income	1,300	356	--
Interest expense	--	--	(224)
Income taxes	1,598	6,202	1,021
Net income from continuing operations	184,676	167,313	146,212
Equity in earnings of discontinued subsidiary	(212)	51,903	9,514
Net income	$ 184,464	$ 219,216	$ 155,726
Basic earnings per share from continuing operations	$ 1.57	$ 1.44	$ 1.43
Discontinued operations	--	0.45	0.09
Basic earnings per share	$ 1.57	$ 1.89	$ 1.52
Diluted earnings per share from continuing operations	$ 1.56	$ 1.44	$ 1.42
Discontinued operations	--	0.44	0.09
Diluted earnings per share	$ 1.56	$ 1.88	$ 1.51

See accompanying notes to the consolidated financial statements.

Puget Energy Condensed

BALANCE SHEETS

(DOLLARS IN THOUSANDS)

AT DECEMBER 31	2007	2006
Assets:		
Investment in and advances to subsidiaries	$ 1,170,257	$ 761,686
Current assets:		
Cash	24	25
Restricted cash	3,994	--
Receivables from affiliates	15,843	24,659
Prepayments and other	545	570
Tax receivable	2,489	388
Total current assets	22,895	25,642
Long-term assets:		
Restricted cash	--	3,813
Deferred income taxes	3,221	3,939
Other	36	217
Total long-term assets	3,257	7,969
Total assets	$ 1,196,409	$ 795,297
Capitalization and liabilities:		
Common equity	$ 1,188,120	$ 785,432
Total capitalization	$ 1,188,120	785,432
Current liabilities:		
Accounts payable	315	325
Payable to affiliates	563	--
Salaries and wages	--	531
Total current liabilities	878	856
Long-term liabilities:		
Other deferred credits	7,411	9,009
Total long-term liabilities	7,411	9,009
Total capitalization and liabilities	$ 1,196,409	$ 795,297

See accompanying notes to the consolidated financial statements.

Puget Energy Condensed Statements of

CASH FLOWS

(DOLLARS IN THOUSANDS) FOR YEARS ENDED DECEMBER 31	2007	2006	2005
Operating activities:			
Net income	$ 184,464	$ 219,216	$ 155,726
Adjustments to reconcile net income to net cash provided by operating activities:			
Deferred income taxes and tax credits – net	718	(3,586)	(252)
Equity in earnings of discontinued subsidiary	--	(51,903)	(9,514)
Equity in earnings of subsidiary	(191,127)	(177,586)	(146,769)
Other	(1,447)	(94)	303
Dividends received from subsidiaries	108,434	109,782	89,199
(Increase) decrease in accounts receivable	279	(355)	(1,617)
(Increase) decrease in tax receivable	(2,101)	(388)	319
Increase (decrease) in accounts payable	(10)	325	--
Increase (decrease) in affiliated payables	563	(5,427)	4,297
Increase (decrease) in accrued tax payable	--	(960)	960
Increase (decrease) in accrued expenses and other	(531)	(4,763)	(208)
Net cash provided by operating activities	99,242	84,261	92,444
Investing activities:			
Cash proceeds from sale of InfrastruX	--	275,000	--
Increase in restricted cash	(181)	(3,813)	--
Investment in subsidiaries	(297,073)	(70,114)	(314,686)
Cash from PE Loan	8,537	(24,303)	--
Net cash provided (used) by investing activities	(288,717)	176,770	(314,686)
Financing activities:			
Dividends paid	(108,434)	(104,332)	(88,071)
Common stock issued	300,544	5,877	317,607
Long-term debt and lease payments	--	(151,849)	(5,000)
Payments made to minority interest	--	(10,451)	--
Issue costs of stocks	(2,636)	(252)	(2,293)
Net cash provided (used) by financing activities	189,474	(261,007)	222,243
Increase (decrease) in cash	(1)	24	1
Cash at beginning of year	25	1	--
Cash at end of year	$ 24	$ 25	$ 1

See accompanying notes to the consolidated financial statements.

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, 2007				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,762	$ 13,019	$ 10,316	$ 5,465
YEAR ENDED DECEMBER 31, 2006				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,074	$ 7,623	$ 7,935	$ 2,762
Deferred tax asset valuation allowance	16,075	--	16,075	--
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

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, 2007				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 2,762	$ 13,019	$ 10,316	$ 5,465
YEAR ENDED DECEMBER 31, 2006				
Accounts deducted from assets on balance sheet:				
Allowance for doubtful accounts receivable	$ 3,074	$ 7,623	$ 7,935	$ 2,762
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	--

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 Executive Vice President 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, 2007, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Executive Vice President 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, 2007 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 Executive Vice President 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 Organizations 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, 2007.

Puget Energy's effectiveness of internal control over financial reporting as of December 31, 2007, 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 Executive Vice President 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, 2007, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Executive Vice President 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, 2007, 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 Executive Vice President 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 Organizations 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, 2007.

PSE's effectiveness of internal control over financial reporting as of December 31, 2007 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, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information called for in this item 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).

BOARD OF DIRECTORS

Ten directors currently constitute the Company's Board of Directors, which is divided into three classes. Class I consists of four directors, Class II consists of three directors and Class III consists of three directors. Generally, one class of directors is elected each year to a three-year term. Directors are elected to hold office until their successors are elected and qualified, or until the directors' earlier resignation or removal. The members of Puget Energy's Board of Directors and Board Committees are the same as the members of PSE's Board of Directors and Board Committees.

Class II – Terms Expiring in 2008

George W. Watson, age 60, has been Executive Chairman of CriticalControl Solutions Corp. a firm offering document imaging and workflow management software to governmental and energy sector clients, located in Alberta, Canada since 2007. Prior to that he was President and CEO of CriticalControl Solutions Corp. from 2003 to 2007 and President and CEO of TransCanada Pipelines, Ltd., an energy company, from 1990 to 1999. He has been a director of Puget Energy and PSE since 2006. He also serves on the boards of CriticalControl Solutions Corp., Canadian Spirit Resources, Inc., Teekay Shipping LNG LLP, Badger Income Fund, Fortress Energy, Inc. and Poplar Creek Resources, Inc.

William S. Ayer, age 53, has been Chairman, President and Chief Executive Officer of Alaska Airlines, Inc. and Alaska Air Group (air transportation) since 2003. He served as Alaska Airlines' President and Chief Operating Officer from November 1997 to January 2002, and as Chief Executive Officer from January 2002 to February 2003. Prior to that, he served as Sr. Vice President Operations for Horizon Air, an Alaska Airlines affiliate. Mr. Ayer has been a director of Puget Energy and PSE since 2005. Mr. Ayer has been a director of Puget Energy and PSE since 2005. Mr. Ayer also serves on the board of the Seattle Branch, Federal Reserve Bank of San Francisco.

Sally G. Narodick, age 62, is retired President of Narodick Consulting, which specialized in strategic planning for the educational technology industry. She retired as Chief Executive Officer of Apex Learning Inc., a venture-backed Internet distance learning company, in 2000. Previously, she served as a Consultant on Strategic Planning for Educational

Technology software for IBM Corporation. Ms. Narodick has been a director of Puget Energy since its incorporation in 1999 and of PSE since 1989. Ms. Narodick also serves as a director of Cray, Inc., Penford Corporation, SumTotal Systems, Inc. and Solutia Inc.

Class III – Terms Expiring in 2009

Craig W. Cole, age 58, has been President and Chief Executive Officer of Brown & Cole Stores, LLC (retail grocery) since 1989. Mr. Cole has served as a director of Puget Energy and PSE since December 1999. In addition, he serves as a director of the National Food Marketing Institute, Washington Food Industry, Brown & Cole Stores, Inc. (and affiliated entities) and as a Regent of the University of Washington.

Tomio Moriguchi, age 72, has served as Chairman of Uwajimaya, Inc. (food and merchandise distributor) since 1994. Prior to that he served as Chairman and Chief Executive Officer from 1994-2007. Mr. Moriguchi has been a director of Puget Energy since its incorporation in 1999 and of PSE since 1988. Mr. Moriguchi also serves as President of the Board of North American Post Publishing, Inc.

Herbert B. Simon, age 64, has been a member of Simon Johnson, L.L.C. (real estate and venture capital projects investment company located in Tacoma, Washington) and its predecessor company since 1985. Mr. Simon has served as a director of Puget Energy and PSE since March 2006. In addition, Mr. Simon serves as a Regent of the University of Washington.

Class I – Terms Expiring in 2010

Phyllis J. Campbell, age 56, was appointed the Lead Independent Director of the Boards of Puget Energy and PSE in May of 2005. She has been President and Chief Executive Officer of The Seattle Foundation (charitable foundation) since 2003. Prior to that, she was Chair of the Community Board of U.S. Bank, Washington from 2001 to 2003 and President of U.S. Bank, Washington (financial institution) from 1993 to 2001. Ms. Campbell has been a director of Puget Energy since its incorporation in 1999 and of PSE since 1993. She also serves as a director of Nordstrom, Inc., Alaska Air Group, Inc. and Joshua Green Corporation (privately held).

Stephen E. Frank, age 66, served as Chairman, President and Chief Executive Officer of Southern California Edison (regulated utility) from 1995 until his retirement in January 2002. Prior to that, he was President and Chief Operating Officer of Florida Power and Light Company from 1990 to 1995. Mr. Frank has been a director of Puget Energy and PSE since 2003. He also serves as a director of Associated Electric & Gas Insurance Services, Northrop Grumman Corp. and Washington Mutual, Inc.

Dr. Kenneth P. Mortimer, age 70, is President Emeritus of the University of Hawaii and Western Washington University. He is also Chancellor Emeritus of the University of Hawaii at Manoa and Senior Associate of the National Center for Higher Education Management Systems. Dr. Mortimer holds a Ph.D. degree from the University of California at Berkeley and an MBA from the Wharton School of the University of Pennsylvania. Dr. Mortimer has been a director of Puget Energy and PSE since 2001.

Stephen P. Reynolds, age 60, has been Chairman, President and Chief Executive Officer of Puget Energy and PSE since May 2005, and was President and Chief Executive Officer from January 2002 to April 2005. Mr. Reynolds has been a director of Puget Energy and PSE since 2002. Mr. Reynolds also serves as a director of Intermec, Inc. and Green Diamond Resources Company.

EXECUTIVE OFFICERS

The information required by this item with respect to Puget Energy is incorporated herein by reference to the material under "Executive Officers of the Registrants" in Part I of this report.

AUDIT COMMITTEE

The Puget Energy Board of Directors has established an Audit Committee in accordance with section 3(a)(58)(A) of the Securities Exchange Act of 1934, as amended. Directors Stephen E. Frank, Dr. Kenneth P. Mortimer, Sally G. Narodick (Chair) and George W. Watson are the members of the Audit Committee.

Each member of the Audit Committee is an independent director under SEC rules and NYSE listing standards. The Board has determined that Ms. Narodick, Mr. Frank and Mr. Watson meet the definition of "audit committee financial expert" under SEC rules.

ADDITIONAL 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 after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). Information may also be obtained via the SEC Internet website at www.sec.gov.

In addition, the following corporate governance materials of Puget Energy are available by clicking on the section Corporate Governance at the Company's website www.pugetenergy.com, or a copy will be mailed to you upon written request to Puget Energy, Inc., Investor Services, P.O. Box 97034, PSE-08N, Bellevue, WA 98009-9734, or by calling (425) 462-3898:

- Corporate Governance Guidelines;
- Corporate Ethics and Compliance Code;
- Charters of Board Committees; and
- Code of Ethics for our CEO and senior financial officers.

If any material provisions of our Corporate Ethics and Compliance Code or our Code of Ethics are waived for our CEO or senior financial officers, or if any substantive changes are made to either code as they relate to any director or executive officer, we will disclose that fact on our website within four business days. In addition, any other material amendments of these codes will be disclosed.

COMMUNICATIONS WITH THE BOARD

Shareholders of Puget Energy and other interested parties may communicate with an individual director or the Board of Directors as a group via U.S. Postal mail directed to: Lead Independent Director of the Board of Directors, c/o Corporate Secretary, Puget Energy, Inc., P.O. Box 97034, PSE-12, Bellevue, Washington 98009-9734. Please clearly specify in each communication the applicable addressee or addressees you wish to contact. All such communications will be forwarded to the intended director or Board as a whole, as applicable.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires the directors and officers of Puget Energy and PSE to file reports of ownership and changes in ownership with respect to the equity securities of the Companies with the SEC. To the Company's knowledge, based on our review of the reports furnished to Puget Energy in 2007 and written representations that no other reports were required, all directors and officers of Puget Energy who are subject to the Section 16 reporting requirements filed the required reports on a timely basis in 2007.

ITEM 11. EXECUTIVE COMPENSATION

PUGET ENERGY
EXECUTIVE COMPENSATION

COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation and Leadership Development Committee are named in their Committee Report on page 147. No members of the Committee were officers or employees of Puget Energy or any of its subsidiaries during the year, were formerly Puget Energy officers or had any relationship otherwise requiring disclosure.

COMPENSATION DISCUSSION AND ANALYSIS

This section provides information about the compensation program in place for the Company's named executive officers who are included in the Summary Compensation Table on page 148 — the CEO, the Chief Financial Officer and the four other most highly compensated executive officers for 2007. It includes a discussion and analysis of the overall objectives of our compensation program and each element of compensation the Company provides.

COMPENSATION PROGRAM OBJECTIVES

The Company's executive compensation program has two main objectives:

- Support sustained Company performance by having talented people running the business.
- Align compensation payment levels with achievement of Company goals.

The following is a discussion of the specific strategies used to accomplish each of these objectives actions by the Compensation and Leadership Development Committee (the Committee) and management to implement these strategies.

1. Our objective of supporting sustained Company performance by having talented people running the business is supported by the following strategies:

- *Designing and delivering compensation programs that attract, motivate, and retain a talented executive team.*

Several factors are critical to attracting and retaining executives for the Company. One is ensuring that total pay opportunity is competitive with similar companies so that new executives will want to join the Company and current executives are not hired away. As described below in the discussion of Compensation Pay Elements (Review of Pay Element Competitiveness), the Committee annually compares executive pay to external market data from similar companies in our industry. Base pay and total direct compensation are targeted to the 50th percentile of our comparator group. Individual pay adjustments are reviewed to see how they position the executive in relation to the median of market pay, while also considering the executive's recent performance and experience level. The Company may choose to pay an individual above or below the median level of market pay when our executive has a role with greater or lesser responsibility than the best comparison job or when our executive's experience and performance exceed those typically found in the market. The Committee determines the pay level for Mr. Reynolds, the Chairman, President and CEO, and reviews and approves Mr. Reynolds' recommendations for pay levels of the other executives.

Another factor critical to motivating our executives, as well as attracting and retaining them, is to provide incentive compensation for meeting and exceeding target levels of annual and long-term goals. It is a highly competitive and dynamic marketplace for talented executives, and other companies look to us when hiring, as shown by one officer level executive recently leaving the Company. By establishing goals, monitoring results, and providing payments and recognition for accomplishment of results, the Company focuses executives on actions that will improve the Company and enhance shareholder value, while also retaining key talent.

A final critical factor in attracting, motivating and retaining executives is providing them with retirement income based upon annual salary and actual bonus paid, as well as tenure. We recognize that executives choose to work for the Company from a variety of other alternative organizations, and one financial goal of employees is to provide a secure future for themselves and their families. The Committee reviews the design of retirement programs provided by competing companies and provides benefits that are commensurate with those of its competitors.

- *Designing and delivering incentive programs that support the Company's business direction as approved by the Board of Directors and align executive interests with those of shareholders and customers.*

In addition to rewarding performance that meets or exceeds goals, our annual and long-term incentives help executives focus on the priorities of our shareholders and customers. Both the annual incentive plan and the long-term incentive plan measure and reward the Company's performance on Service Quality Indices (SQIs). These reporting measures were developed in collaboration with the Company's regulator and provide customers with a report card on the Company's customer service and reliability. In fact, we provide an annual accounting on these 11 measures to our customers each year. Additional key measures used for determining incentives are Earnings Per Share (EPS) in the annual incentive plan and Relative Total Shareholder Return (Relative TSR) in the long-term incentive plan. EPS and Relative TSR are important shareholder performance measures, but they also indicate to our customers that the Company will have the financial strength needed for long-term sustainability.

- *Executing the Company's succession planning process to ensure that executive leadership continues uninterrupted by executive retirements or other personnel changes.*

The Chairman, President and CEO leads the talent reviews and succession planning through meetings with his executive team. Each executive conducts talent reviews of senior employees who have high potential for assuming greater responsibility in the Company. The talent reviews include evaluations prepared within the Company and by external organizational development consultants. The Committee annually reviews these assessments of executive readiness, the plans for development of the Company's key executives, and progress made on these succession plans. The Committee directly participates in discussion of succession plans for the position of Chairman, President and CEO.

2. Our objective of aligning compensation payment levels with achievement of Company goals is supported by the following strategy:

- *Placing a significant portion of each executive's total direct compensation at risk to align executive compensation with financial and operating performance. Total direct compensation is base salary plus annual and long-term incentive pay, and does not include retirement plan accruals.*

When Company results are above expectations, total direct compensation is higher than our target of the 50th percentile of our comparator group. If results are below expectations, total direct compensation is lower than this targeted level. As described above as "pay for performance," the Company's variable pay program helps focus executives and creates a record of their results. When the performance of the executive team and all employees is better than planned, customers and shareholders benefit. Customers receive good customer service and reliable energy supplies at the least cost. Shareholders have the opportunity to receive dividends and increases in the value of their investment. By keeping a significant portion of pay at risk, the Company will not pay for results unless they are achieved. This is also why the Company targets the median pay of the market when performance goals are met, but will pay higher when performance exceeds targets.

COMPENSATION PROGRAM ELEMENTS

This section continues the detailed discussion of the Company's compensation program by identifying the elements of the program and examining how these elements function and why the Committee chooses to include the items in the compensation program.

The Company's compensation policies encompass a mix of base salary, annual and long-term incentive compensation, health and welfare benefits, retirement programs, and a small number of perquisites. The Company also provides certain change in control benefits to executives. The total package is designed to provide participants with appropriate incentives that are competitive with the comparator group and achieve current operational performance and customer service goals as well as the long-term objective of enhancing shareholder value. The Company does not have a specific policy regarding the mix of cash and non-cash compensation elements, but arrives at a mix of pay by setting each compensation element relative to market comparators. The Company delivers compensation through cash and stock-based programs, because cash provides liquidity for employees while stock increases the connection to shareholders. Long-term performance-based incentives are designed to comprise the largest portion of each executive's incentive pay. As an example, the mix of annual salary and annual and long-term incentive targets for the Chairman, President and CEO in 2007, if all annual and long-term performance goals were achieved, was 28% annual salary, 24% target annual incentive, and 48% target long-term incentive. Annually the Committee reviews total compensation opportunity and actual total compensation received over the prior years by each officer in the form of a tally sheet. This review helps inform the Committee's decisions on program designs by allowing the Committee to review overall pay received in relation to Company results.

Review of Pay Element Competitiveness

In making compensation decisions on base salary, annual and long-term incentive programs, management prepares comprehensive surveys of pay for review by the Committee and the Committee's outside executive pay consultant, Towers Perrin. The surveys summarize data provided by the Towers Perrin Energy Services survey for a selection of utility and other companies that are most similar in scope and size to Puget Energy. For the review of compensation pay levels and practices in 2006, we included the following utility companies that were all of similar scope (generally $1.5 billion — $7.0 billion revenue and $4.0 billion — $10.0 billion asset size) and also participated in the Towers Perrin 2007 Energy Services survey:

1	Allegheny Energy	7	MDU Resources	13	Pinnacle West Capital
2	Alliant Energy	8	NSTAR	14	Portland General Electric
3	Ameren	9	New York Power Authority	15	SCANA
4	Atmos Energy	10	Nicor	16	Westar Energy
5	Avista	11	OGE Energy	17	Wisconsin Energy
6	Great Plains Energy	12	PNM Resources		

Base Salary

Base salaries are generally targeted at the 50th percentile for the comparator group. Actual salaries vary by individual and depend on additional factors, such as expertise, individual performance achievement, level of experience and level of contribution relative to others in the organization.

Generally, base salaries for executives are administered on a subjective, individual basis by the Committee using as a guideline, median salary levels of a select group of electric and combination gas and electric companies and other comparable companies from the group above, as well as internal equity among executives. We recognize that it is necessary to provide executives with a portion of total compensation that is delivered each month and provides a balance to other pay elements that are at risk.

Base Salary Adjustments

The Committee reviewed Mr. Reynolds' performance and, based on his results and market comparison, his base salary for 2007 was increased from $775,000 per year to $800,000, a 3.23% increase. For the other named executives, Mr. Reynolds evaluated their performance during 2006 and recommended increases to the Committee based on individual performance. The recommended increases were similar to the range of salary increases awarded to all employees. The Committee reviewed market comparisons and found the proposed increases appropriate. These increases were: Mr. Valdman, a 3.02% increase to $375,000; Ms. O'Connor, a 3.81% increase to $300,000; Ms. McLain, a 0.73% increase to $275,000; Mr. Markell, a 2.61% increase to $275,000 (Mr. Markell also received a promotional increase of 9.09% to $300,000 when he was promoted on May 16, 2007 to Executive Vice President and Chief Financial Officer); and Ms. Harris, a 5.66 % increase to $280,000 (Ms. Harris also received a promotional increase of 7.14% to $300,000 when she was promoted on May 16, 2007 to Executive Vice President and Chief Resource Officer).

Annual Incentive Compensation

In addition to reviewing base salaries paid by our market comparator group, we also review annual incentive payments through an annual review of total cash compensation (base salaries plus incentives). Total cash compensation is targeted at the 50th percentile of total compensation for the industry comparator group if the Company's annual performance goals are achieved at target. If performance goals significantly exceed target, total cash compensation can approach the 75th percentile.

All PSE employees, including executive officers, participate in an annual incentive program referred to as the "Goals and Incentive Plan." The plan is designed to provide financial incentives to executives for achieving desired annual operating results while meeting the Company's service quality commitment to customers. The Company's service quality commitment is measured by performance against Service Quality Indices (SQIs), set forth below. These are the same SQIs for which the company is accountable to the Washington Commission.

- **Customer Satisfaction**
  — Overall customer satisfaction, Customer access center, Gas field services and Washington Commission complaints
- **Customer Service**
  — Calls answered "live", On-time appointments and Disconnects for non-pay
- **Safety and Reliability**
  — Gas emergency response, Electric emergency response, Non-storm outage frequency and Non-storm outage duration

The 2007 plan had a funding level based on Earnings Per Share (EPS) and attainment of SQIs as shown in the table below. The Committee can adjust earnings per share used in annual incentive calculation to exclude nonrecurring items that are outside the normal course of business for the year. Individual awards were based on performance against team and individual goals. Individual goals were developed from the overall corporate goals for 2007:

- **Great Customer Service** — Provide noticeably-improved service to our customers by leveraging new systems, improving processes and enhancing employee development and training.
- **Generation and Delivery** — Manage our existing resources and acquire needed new ones in a way that meets customers' needs and provides a fair return to shareholders.
- **Be a Good Neighbor** — Through our energy efficiency, corporate giving and employee involvement efforts, demonstrate to our key constituents and communities that we accept leadership responsibility in the effort to make our region better.
- **Dedication to Employees** — Focus on safety, teamwork, process improvements, technology and controls to make the Company truly a great place to work.
- **Own it —** Each employee should manage the resources under their control as if they owned them.
- **Learn from the past** — Examine past practices, including significant event response efforts, and apply lessons learned to develop and implement solutions that add value and enhance customer service and community involvement.

Annual Incentive Performance Payout Scale

Performance	2007 EPS	SQI*	Funding Level
Maximum	$1.75	10/11	205%
Target	1.57	10/11	100%
Trigger Payout Funding	1.43	10/11	30%
2007 Actual Performance	$1.62	9/11	106.2%

* SQI Results of 5/11 or better required for any incentive payout funding. SQI results below 10/11 reduces funding (e.g. 9/11 = 90%, 8/11 = 80% etc.).

Actual performance for 2007 was better than the target level for EPS, but below target for SQI achievement. Puget Sound Energy EPS was $1.62, and SQI achievement was 9 out of 11, leading to a funding level of 106.2% (118% x 90% = 106.2%).

For 2007, the target incentives for this plan varied by executive officer as shown in the table below. The maximum incentive for exceptional performance in this plan is twice the target incentive. The performance goals for the named executives of PSE included EPS performance and other specified operational goals. After considering performance on individual and team goals, which were met by each executive officer, the following amounts were paid at 106.2% of target:

Name	Target Incentive (% of Base Salary)	2007 Actual Incentive Paid
Stephen P. Reynolds	85%	$722,160
Bertrand A. Valdman	60%	238,950
Eric M. Markell	60%	175,230
Kimberly J. Harris	60%	175,230
Jennifer L. O’Connor	45%	143,370
Susan McLain	45%	131,423

Long-Term Incentive Compensation

Total direct compensation (base salary, annual incentive and long-term incentives) opportunities are designed to be competitive with market practices, generally targeting the 50th percentile. The Puget Energy 2005 Long Term Incentive Plan (LTIP), approved by shareholders in 2005, provides for several forms of multi-year incentive grants, both equity and cash-based awards. Even though the LTIP provides many types of awards, the Company’s use of the plan typically divides into two types of grants — annual grants of Performance Shares and Performance-Based Restricted Stock to all eligible employees, and new employment grants to newly hired executives. The Company does not use stock options frequently, even though permitted under the LTIP, because the Committee believes that performance shares and performance-based restricted stock generally have better incentive value for executives in a utility industry company.

The Company makes annual grants of Performance Shares and Performance-Based Restricted Stock to PSE executives and key employees. The table below shows the mix of grants for the cycles that were active in 2007. Beginning with the 2006-2008 grant cycle, the committee began granting a combination of Performance Shares and Performance-Based Restricted Stock. The committee adopted a mix for grants of 50% each for executive officers, except the CEO is granted 70% Performance Shares and 30% Performance-Based Restricted Stock to better align the CEO’s pay at risk with the overall Company performance.

Grant Cycle	Performance Shares	Performance Based Restricted Stock
2005-2007	100%	0%
2006-2008*	50%	50%
2007-2009*	50%	50%

* *CEO grants are split 70% Performance Shares and 30% Performance-Based Restricted Stock*

The Committee establishes the number of LTIP shares that will be paid to each plan participant by evaluating the actual payment and forecast target payment of long-term incentive awards of our market comparator group for comparable levels of responsibility. The Committee generally does not consider previously granted awards or the level of accrued value from prior programs when granting annual incentive awards or making new LTIP grants. Each year’s grant is primarily viewed in the context of the compensation opportunity needed to maintain the Company’s competitive position relative to the comparator group. Target Performance Share awards are calculated based on a percentage of annual salary, and are translated into a target number of shares using the average of the month ending stock prices from the three months prior to the start of the performance period. Targets for 2007 were 170% of base salary for Mr. Reynolds, 110% for Mr. Valdman, Mr. Markell and Ms. Harris, and 95% for Ms. O’Connor and Ms. McLain.

The points below summarize the performance measures and design of the LTIP grants that are currently outstanding and those which completed during 2007.

Performance Shares:

- A Performance Share grant establishes a target number of shares of stock that will be paid to the participant if the Company achieves the targeted level of performance during the multi-year performance cycle. The actual award paid is based on Company performance relative to target, subject to a minimum threshold level of performance.

- The performance share grant is calculated based on Puget Energy's total shareholder return relative to the EEI Combination Gas & Electric Investor Owned Utilities Index and performance outcomes on a set of service quality measures during the performance period. The grant requires a threshold performance of relative total shareholder return at the 25th percentile, and pays at target level if total shareholder return is at the 50th percentile and 10 out of 11 SQIs are met.
- At the completion of the performance cycle, if the Performance Share grant is paid, the participant receives shares of stock and a cash payment equivalent to the dividends that would have been paid on this number of shares during the performance period.
- Participants who are meeting or exceeding shareholder ownership guidelines may elect to receive up to 50% of the value of the Performance Shares in cash.
- The Performance Shares have interim calculations ("banking") at the end of Year 1 for 15% of the shares, at the end of Year 2 for 25%, and at the conclusion of the performance period in Year 3 for the remaining 60% of the shares.

Performance-Based Restricted Stock:

- A Performance-Based Restricted Stock grant is a grant of shares that vest based on a combination of continued service and attainment of Company performance. The Performance-Based Restricted Stock vests in installments over a three-year period only if a target service quality measure is met and the participant remains employed with the Company.
- Vesting is based on the Company meeting or exceeding 8 out of 11 SQIs and the participant continuing employment through the vesting dates at the end of Year 1 (15% vesting), Year 1 (25% vesting) and Year 3 (60% vesting).

LTIP Performance:

- 2005-2007 Grant: Overall performance on the cumulative grant for the 3 year period was 89.5%. Performance on relative TSR was at the 45.7 percentile versus the comparator group and the service quality measures achieved 90% of target. The plan had a performance share banking of: 13.4% in 2005; 22.4% in 2006 and 53.7% in 2007. Notwithstanding the Company's overall performance relative to the comparator group, actual payments of Performance Share awards for the 2005-2007 LTIP cycle to certain named executives were reduced by the Committee in order to correct overpayments to the executives of a prior year's award resulting from a clerical error in the computation of the relevant year's TSR. The 2005-2007 LTIP cycle awards were reduced, in the case of Mr. Reynolds by 11,871 shares, in the case of Mr. Valdman by 2,277 shares, in the case of Ms. McLain by 1,327 shares, in the case of Mr. Markell by 1,132 shares, and in the case of Ms. Harris by 1,065 shares.
- 2006-2008 Grant: Overall performance on the cumulative grant for the first two years was 140.75%. Performance on relative TSR was 80 percentile versus the comparator group and the service quality measures achieved 90% of target. The plan had a performance banking of: 16.1% in 2006 and 35.2% in 2007.
- 2007-2009 Grant: Overall performance for the first year of this grant was 140.75%. Performance on relative TSR was at the 80.0 percentile versus the comparator group and the service quality measures achieved 90% of target. The plan had a performance share banking of 21.1% for the first year.

New employment grants, usually in the form of restricted stock, performance shares, or in one case, non-qualified stock options, are made to attract an executive to the Company, and often are also used to replace value the candidate would forfeit from similar awards by moving to the Company.

Timing of Grants

The Committee approves LTIP grants in the first quarter of the year at the regular meeting of the Committee, which typically is within a month after the Company has publicly released a report of its annual earnings. Due to administrative requirements, the Committee may make the effective date of grants up to five business days after the date of Committee action. The Committee may also make grants of stock options or stock appreciation rights to selected executive officers in appropriate circumstances. These circumstances would generally include the hiring of new executives or the need to retain current executive officers. The Company's policy for pricing stock options is to establish the grant price as the fair market value of Puget Energy stock on the date that the Committee approves the grant of stock options. The LTIP defines fair market value as the average of the high and low price for Puget Energy stock on the date of grant. The options granted at employment for Mr. Reynolds were priced on January 8, 2002, the date that the Committee approved Mr. Reynolds as President and CEO. There have been no option grants to executives since these January 8, 2002 employment option grants.

Stock Ownership

The Company has established stock ownership guidelines to be achieved over a five-year period for PSE officers and key managers. For executives, holding a certain amount of stock relative to their current income helps to strengthen their alignment to shareholders. The guidelines range from five times base salary for the Chairman, President and CEO to two times base salary for the named executive officers to 50% of base salary for other key employees. Directly owned shares, share equivalents in the deferred compensation plan, and contingent shares in the LTIP that are forecast to be paid, count towards meeting the stock ownership guidelines. The Company has determined that as of December 31, 2007, all of the Named Executive Officers met or exceeded their guidelines. Officers and directors of the Company are not allowed to own derivatives of Puget Energy stock, nor are they allowed to own shares in margin accounts.

Impact of Accounting and Tax Treatment of Compensation

The accounting treatment of compensation generally has not been a factor in determining the amounts of compensation for our executive officers. However, the Company considers the accounting impact of various program designs to balance the potential cost to the Company with the benefit/value to the executive. The Company considers the tax impact of long-term incentive compensation awards, and therefore to the extent practical, strives to deliver pay that qualifies under IRS section 162(m) as performance-based to obtain a corporate tax deduction. Under 162(m), the Company may not deduct compensation expense for the named executives if that expense is over one million dollars, except that performance-based pay is excluded from the total pay applying to 162(m). Our LTIP grants of performance-based restricted stock and performance shares are designed to meet the performance-based qualification and therefore are fully tax deductible. Only Mr. Reynolds has pay that normally exceeds the one million dollar level, and the majority of this pay is performance-based and qualifies for deduction under 162(m), although Mr. Reynolds received equity awards in prior years that were not qualified under 162(m). The Committee has the right under the 2005 LTIP to exercise its discretion to decrease, but not to increase, the payment amount of LTIP awards from the grant's performance-based calculation.

Retirement Plans — Supplemental Executive Retirement Plan (SERP)

The Company maintains the SERP for executives to provide a benefit that is coordinated with the tax-qualified PSE Retirement Plan. Without the addition of the SERP, these executives would receive lower percentages of replacement income during retirement than other employees. All the Named Executive Officers except Mr. Reynolds participate in the SERP. When Mr. Reynolds was hired, he elected to receive an annual contribution to his account in the Deferred Compensation Plan for Key Employees in lieu of participating in the SERP, as described in the following paragraph. He participates in the Retirement Plan. Additional information regarding the Retirement Plan and the SERP, as well as current balances, is shown in the "2007 Pension Benefits" table.

Retirement Plans — Deferred Compensation Plan

The Company's Named Executive Officers are eligible to participate in the Deferred Compensation Plan. The Deferred Compensation Plan provides executives an opportunity to defer up to 100% of base salary, annual incentive bonus and vested performance shares, plus receive additional Company contributions made by PSE, into an account with four investment tracking fund choices. The funds mirror performance in major asset classes of bonds, stocks, Puget Energy stock, and an interest crediting fund that changes rate quarterly based on corporate bond rates. Similar to the SERP, the Deferred Compensation Plan is intended to allow the executives to defer current income, without being limited by the Internal Revenue Code contribution limitations for 401(k) plans. The Company contributions are also intended to restore benefits not available to executives under PSE's tax-qualified plans due to Internal Revenue Code limitations on compensation and benefits applicable to those plans. Mr. Reynolds receives an annual Company contribution to his Deferred Compensation account equal to 15% of the base salary and annual incentive payment he received during the prior year. This account is a feature of Mr. Reynolds' employment agreement. Additional information regarding the Deferred Compensation Plan and Mr. Reynolds' employment agreement arrangement, as well as current balances, is shown in the "2007 Nonqualified Deferred Compensation" table.

Post Termination Benefits

The Company provides change in control agreements to its Named Executive Officers to establish in advance the terms of payments if the Company should have a change in control. Change of control agreements are important for two reasons. First, many executives when joining a new company require a level of assurance that they will receive pay in the event of a change in control after they join the company. Secondly, the Company provides change in control agreements so that the executive officers are focused on the Company's ongoing operations and not distracted by the employment uncertainty that can arise in the event of a change in control. In 2006, the Committee reviewed and amended existing change in control arrangements in light of benchmarking information provided by Towers Perrin, and believes that the amended arrangements provide competitive benefits. The change in control agreements call for accelerated vesting of equity awards in the event of a change in control, meaning that participants will receive accelerated vesting even if their employment continues with the new company. Payment of severance benefits, however, requires a "double trigger" of change in control and the executive not continuing employment with the new company, except Mr. Reynolds' employment agreement provides that payment of severance benefits will be made at the time of a change in control. The "Potential Payments Upon Termination or Change in Control" section describes the change in control agreements with the Named Executive Officers as well as other plans and arrangements that would provide benefits on termination of employment, and the estimated potential incremental payments upon termination or a change in control based on an assumed termination or change in control date of December 31, 2007. The definitive proxy statement relating to the merger describes the anticipated amount of such benefits that would be provided upon occurrence of the merger.

Other Compensation

In addition to base salary and annual and long-term incentive award opportunities, the Company also provides the Named Executive Officers with benefits and perquisites targeted to competitive practices. The executives participate in the same group health and welfare plans as other employees. Company vice presidents and above, including the executives, are eligible for additional disability and life insurance benefits. The executives are also eligible to receive reimbursement for financial planning, tax preparation, and legal services, business club memberships and executive physicals. The reimbursement for financial planning, tax preparation, and legal services is provided to allow executives to concentrate on their business responsibilities. Business club memberships are provided to allow access for business meetings and business events at club facilities and executives are required to reimburse the Company for individual use of club facilities. Perquisites do not make up a significant portion of executive compensation, amounting to less than $10,000 in total for each executive in 2007.

Relationship Among Compensation Elements

A number of compensation elements increase in absolute dollar value as a result of increases to other elements. Base salary increases translate into higher dollar value incentive opportunity for annual and long-term incentives, because each plan operates with a target level award set as a percentage of base salary. Base salary increases also increase the level of retirement benefits, as do actual annual incentive plan payments. Some key compensation elements are excluded from consideration when determining other elements of pay. Retirement benefits exclude LTIP payments in the calculation of qualified retirement (pension and 401(k)) and SERP benefits.

COMPENSATION AND LEADERSHIP DEVELOPMENT COMMITTEE REPORT

The Board of Directors of Puget Energy delegates responsibility to the Compensation and Leadership Development Committee to establish and oversee the Company's executive compensation program. For a discussion of the Committee's policies and procedures, see the "Compensation and Leadership Development Committee". Each member of the committee meets the independence requirements of the SEC and the NYSE.

The Compensation and Leadership Development Committee has reviewed and discussed the "Compensation Discussion and Analysis" with the Company's management. Based on this review and discussion, the committee recommended to the Board of Directors, and the Board has approved, that the "Compensation Discussion and Analysis" be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2007 for filing with the SEC.

Compensation and Leadership
Development Committee of
Puget Energy, Inc.

Stephen E. Frank, Chair
William S. Ayer
Herbert B. Simon

SUMMARY COMPENSATION TABLE

The following information is furnished for the year ended December 31, 2007 with respect to the "Named Executive Officers" during 2007. The positions and offices below are at Puget Energy and PSE, except that Mr. Valdman, Ms. Harris and Ms. McLain are officers of PSE only. Salary compensation includes amounts deferred at the officer's election.

Name and Principal Position	Year	Salary	Bonus	Stock Awards[1]	Option Awards[1]	Non-Equity Incentive Plan Compensation[2]	Change in Pension Value and Above Market DCP[3]	All Other Compensation[4]	Total
Stephen P. Reynolds	2007	$794,896	$ --	$2,949,696	$ --	$722,160	$ 20,328	$330,647	$4,817,727
Chairman, President and	2006	769,901	--	1,757,969	99,793	614,672	28,882	277,221	3,548,438
Chief Executive Officer									
Bertrand A. Valdman	2007	$372,754	$ --	$ 747,622	$ --	$238,950	$107,558	$ 48,111	$1,514,995
Executive Vice President	2006	361,142	--	327,578	--	230,958	100,208	50,225	1,070,111
and Chief Operating Officer									
Eric M. Markell	2007	$288,154	$ --	$ 447,382	$ --	$175,230	$175,460	$ 31,968	$1,118,194
Executive Vice President	2006	266,264	--	178,994	--	127,534	160,913	32,906	766,611
and Chief Financial Officer									
Susan McLain	2007	$274,592	$ --	$ 454,672	$ --	$131,423	$ 85,929	$ 28,517	$ 975,133
Senior Vice President	2006	271,367	--	182,559	--	129,914	189,127	30,309	803,276
Operations									
Jennifer L. O'Connor	2007	$297,754	$ --	$ 348,608	$ --	$143,370	$125,354	$ 29,002	$ 944,088
Senior Vice President and	2006	287,163	--	166,226	--	137,528	122,079	32,192	745,188
General Counsel, Chief Ethics and Compliance Officer									
Kimberly J. Harris	2007	$288,604	$ --	$ 315,034	$ --	$175,230	$ 74,582	$ 22,876	$ 876,326
Executive Vice President	2006	262,346	--	142,777	--	126,107	102,350	21,521	655,101
and Chief Resource Officer									

1 *Reflects accounting expense recognized during the year for all outstanding stock awards, in accordance with SFAS No. 123R. This includes amounts recognized for grants of performance-based LTIP awards made in and prior to the year. The actual payment of the LTIP grants depends on Company performance and requires a threshold performance before any payment is made. Assumptions used in the calculation of these amounts are included in footnote 16 to the Company's audited financial statements for the fiscal year ended December 31, 2007 included in the Company's Form 10-K filed with the SEC on February 29, 2008 (the "2007 Form 10-K"). A description of the LTIP grants appears in the "Compensation Discussion and Analysis" section and the estimated threshold, target and maximum amounts that might be paid for the 2007 LTIP grants is set forth in the "2007 Grants of Plan-Based Awards" table. For Mr. Reynolds in 2006, $99,793 represents accounting expense related to his stock options that were fully vested in 2006.*

2 *Reflects annual cash incentive compensation paid under the 2007 Goals & Incentive Plan. These amounts are based on performance in 2007, but were determined by the Compensation and Leadership Development Committee in February 2008 and paid shortly thereafter or deferred at the officer's election. The 2007 Goals & Incentive Plan is described in further detail under "Compensation Discussion and Analysis". The threshold, target and maximum amounts of annual cash incentive compensation that might have been paid for 2007 performance is set forth in the "2007 Grants of Plan-Based Awards" table.*

3 *Reflects the aggregate increase in the actuarial present value of the officer's accumulated benefit under all pension plans during the year. The amounts are determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements and includes amounts which the officer may not currently be entitled to receive because such amounts are not vested. Information regarding these pension plans is set forth in further detail under "2007 Pension Benefits". Mr. Reynolds does not participate in the SERP, and his accumulated benefit shown is only from the qualified pension plan. Also included in this column are the portion of Deferred Compensation Plan earnings that are considered above market. These amounts for 2007 are: Mr. Reynolds $420, Ms. O'Connor, $544; Ms. McLain, $315; and Mr. Markell $252. These amounts for 2006 are: Mr. Reynolds, $423; Ms. O'Connor, $567; Ms. McLain, $226; and Mr. Markell, $244. See the "2007 Non-Qualified Deferred Compensation" table for all Deferred Compensation Plan earnings.*

4 *All Other Compensation is shown in detail on the table below.*

Detail of All Other Compensation

Name	Perquisites and Other Personal Benefits[1]	Tax Reimbursements	Discounted Securities Purchases	Payments/ Accruals on Termination Plans	Registrant Contributions to Defined Contribution Plans[2]	Insurance Premiums	Other[3]
Stephen P. Reynolds	$6,418	$ --	$ --	$ --	$321,391	$ --	$2,838
Bertrand A. Valdman	9,367	--	--	--	37,636	--	1,108
Eric M. Markell	3,597	--	--	--	27,141	--	1,230
Susan McLain	--	--	--	--	26,241	--	2,276
Jennifer L. O'Connor	2,000	--	--	--	26,317	--	685
Kimberly J. Harris	6,332	--	--	--	15,536	--	1,007

1 *Annual reimbursement for financial planning, tax planning, and/or legal planning, up to a maximum of $5,000 for Mr. Reynolds and Mr. Valdman, $2,500 for other Named Executive Officers. During an executive's initial year, the reimbursement for financial, tax, and legal planning is higher, recognizing the cost of the initial plans. None of the Named Executive Officers received benefits for the initial plan, but if they had, the maximum reimbursement would have been $9,500 financial planning and $5,000 legal (Mr. Reynolds and Mr. Valdman); $5,000 financial planning and $2,500 legal (other executives). Club use is primarily for business purposes, but Company club expense is included where the executive is also able to use the club for personal use. Expenses for personal club use are directly paid by the executive, not PSE.*

2 *Includes Company contributions during 2007 to PSE's Investment Plan (a tax qualified 401k plan) and the Deferred Compensation Plan. For Mr. Reynolds, this includes the Company contribution to the Performance-Based Retirement Equivalent Stock Account, which is described in more detail in the "2007 Nonqualified Deferred Compensation" section.*

3 *Other column includes:*

Stephen P. Reynolds	*$2,838 imputed income of life insurance*
Bertrand A. Valdman	*$1,108 imputed income on life insurance*
Eric M. Markell	*$1,230 imputed income on life insurance*
Susan McLain	*$2,276 imputed income on life insurance*
Jennifer L. O'Connor	*$685 imputed income on life insurance*
Kimberly J. Harris	*$1,007 imputed income on life insurance*

2007 Grants of Plan-Based Awards

The following table presents information regarding 2007 grants of annual incentive awards and LTIP awards, including the range of potential payouts for the annual incentive awards and performance share awards.

		Estimated Future Payouts under Non-Equity Incentive Plan Awards			Estimated Future Payouts under Equity Incentive Plan Awards			
Name	Grant Date	Threshold	Target	Maximum	Threshold	Target	Maximum	Grant Date Fair Market Value
Stephen P. Reynolds								
Annual Incentive (1)	1/1/2007	$204,000	$680,000	$1,672,800				n/a
LTIP PS (2)	3/1/2007				13,607	45,355	79,371	$1,127,979
LTIP RS (3)	3/1/2007					16,525	16,525	410,977
Bertrand A. Valdman								
Annual Incentive (1)	1/1/2007	$ 67,500	$225,000	$ 553,500				n/a
LTIP PS (2)	2/28/2007				2,948	9,826	17,196	$ 242,407
LTIP RS (3)	2/28/2007					8,354	8,354	206,093
Eric M. Markell								
Annual Incentive (1)	1/1/2007	$ 49,500	$165,000	$ 405,900				n/a
LTIP PS (2)	2/28/2007				1,867	6,223	10,890	$ 153,521
LTIP RS (3)	2/28/2007					5,291	5,291	130,529
Susan McLain								
Annual Incentive (1)	1/1/2007	$ 37,125	$123,750	$ 304,425				n/a
LTIP PS (2)	2/28/2007				2,192	7,306	12,786	$ 180,239
LTIP RS (3)	2/28/2007					5,291	5,291	130,529
Jennifer L. O'Connor								
Annual Incentive (1)	1/1/2007	$ 40,500	$135,000	$ 332,100				n/a
LTIP PS (2)	2/28/2007				2,037	6,789	11,881	$ 167,485
LTIP RS (3)	2/28/2007					5,772	5,772	142,395
Kimberly J. Harris								
Annual Incentive (1)	1/1/2007	$ 49,500	$165,000	$ 405,900				n/a
LTIP PS (2)	2/28/2007				1,901	6,336	11,088	$ 156,309
LTIP RS (3)	2/28/2007					5,387	5,387	132,897

1 *Annual Goals and Incentive Plan. As described in the "Compensation Discussion and Analysis", the plan has dual funding triggers in 2007 of $1.43 EPS and SQI performance of 5/11. Payment would be $0 if either trigger is not met. The threshold estimate assumes $1.43 EPS and SQI performance at 10/11. The target estimate assumes $1.57 EPS and SQI performance at 10/11. The maximum estimate assumes $1.76 EPS or higher and SQI performance at 11/11.*

2 *LTIP Performance Shares for 2007-2009. As described in the "Compensation Discussion and Analysis", Performance Shares are calculated at the end of the three year performance period based on Company results in relative TSR and SQI performance. Threshold estimate assumes that Puget Energy's TSR is below the 25th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 30% of target. Target estimate assumes that Puget Energy's TSR equals the 50th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 100% of target. Maximum estimate assumes that Puget Energy's TSR is at or above the 85th percentile of the comparison group and the SQI result is 10/11, for an overall payment of 175% of target. Payments of Performance Shares vary significantly and have paid at the following percentages of target: 2000-2003, 110%, 2001-2004, 30%, 2002-2005, 20%, 2003-2006, 0%, 2004-2006, 17.5% and 2005-2007, 89.5%.*

3 *LTIP Performance-Based Restricted Stock for 2007-2009. As described in the "Compensation Discussion and Analysis", the 2007-2009 plan included two types of awards. The Performance-Based Restricted Stock grants vest based on achievement of 8/11 SQIs and continued service during the performance cycle. Target and Maximum estimates both assume that all shares vest.*

4 *Grant Date Fair Value is calculated as the target number of shares at the closing price of Puget Energy stock on March 1, 2007 of $24.87 for Mr. Reynolds and February 28, 2007 of $24.67 for the other Named Executive Officers.*

Outstanding Equity Awards at 2007 Fiscal Year-End

The following table provides information regarding outstanding stock options and unvested stock awards held as of December 31, 2007.

Name	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock Held that Have Not Vested	Market Value of Shares or Units of Stock Held that Have Not Vested	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested
Stephen P. Reynolds									
(1)	300,000	0	0	$22.51	1/8/2012	40,000	$1,097,200		
(2)								40,000	$1,097,200
(3)						25,790	707,410	73,195	2,007,746
(4)						9,570	262,502	83,848	2,299,940
Bertrand A. Valdman									
(5)						2,000	$ 54,860		
(3)						5,785	158,683	19,706	$ 540,537
(4)						2,073	56,870	22,223	609,580
Eric M. Markell									
(3)						3,679	$ 102,787	12,764	$ 350,123
(4)						1,313	36,017	14,075	386,065
Susan McLain									
(3)						3,747	$ 98,378	12,925	$ 354,532
(4)						1,313	36,017	14,075	386,065
Jennifer L. O'Connor									
(3)						3,967	$ 108,808	12,545	$ 344,102
(4)						1,432	39,293	13,955	382,789
Kimberly J. Harris									
(3)						3,637	$ 99,776	12,390	$ 339,866
(4)						1,337	36,671	14,330	393,073

[1] *Stock Option awards granted 1/8/2002. Restricted Stock and Restricted Stock Unit Awards vest 15,000 shares 1/8/2008, and 25,000 shares May 6, 2008.*

[2] *Performance-Based Restricted Stock grant will vest all 40,000 shares May 6, 2008.*

[3] *Long-Term Incentive Plan grant for 2006-2008 cycle is forecast to finish between target and maximum. Figures are shown at maximum.*

[4] *Long-Term Incentive Plan grant for 2007-2009 cycle is forecast to finish between target and maximum. Figures are shown at maximum.*

[5] *Restricted Stock award granted at hire will have remaining 2,000 shares vest 12/4/2008.*

Stock Vested in 2007

The following table provides information regarding vesting of stock awards during 2007. No stock options were exercised during 2007.

Name	Stock Award Number of Shares Acquired on Vesting	Value Realized on Vesting
Stephen P. Reynolds [1,2]	69,063	$1,894,398
Bertrand A. Valdman [2,3]	22,661	621,591
Eric M. Markell [2]	13,536	371,292
Susan McLain [2]	13,631	373,898
Jennifer L. O'Connor [2]	9,823	269,456
Kimberly J. Harris	7,562	207,426

1 *Vesting of 8,000 shares of employment grant restricted stock on 1/8/2007.*

2 *Payment of 2005-2007 LTIP cycle at 89.5% of target and vesting of 25% of 2006-2008 and 15% vesting of 2007-2009 Performance-Based Restricted Stock grants.*

3 *Vesting of part of employment grant Restricted Stock*

2007 Pension Benefits

Puget Energy, PSE and its affiliates maintain two pension plans: the Retirement Plan for Employees of Puget Sound Energy, Inc. (the "Retirement Plan") and the Puget Sound Energy, Inc. Supplemental Executive Retirement Plan (the "SERP"). The following table provides information for each of the Named Executive Officers regarding the actuarial present value of the officer's accumulated benefit and years of credited service under the Retirement Plan and the SERP. The present value of accumulated benefits was determined using interest rate and mortality rate assumptions consistent with those used in the Company's financial statements. Except as described below in footnote (1), relating to Mr. Reynolds, each of the Named Executive Officers participates in both plans.

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit [2,3]	Payments During Last Fiscal Year
Stephen P. Reynolds [1]	PSE Retirement Plan	6.0	$121,986	$ --
	PSE SERP	n/a	n/a	n/a
Bertrand A. Valdman	PSE Retirement Plan	4.1	61,966	--
	PSE SERP	4.1	273,499	--
Eric M. Markell	PSE Retirement Plan	5.4	103,022	--
	PSE SERP	5.4	484,507	--
Susan McLain	PSE Retirement Plan	19.7	234,012	--
	PSE SERP	19.7	954,655	--
Jennifer L. O'Connor	PSE Retirement Plan	4.9	73,564	--
	PSE SERP	4.9	322,753	--
Kimberly J. Harris	PSE Retirement Plan	8.7	120,111	--
	PSE SERP	8.7	293,712	--

1 *Mr. Reynolds participates in the Retirement Plan, but does not participate in the SERP. In lieu of participating in the SERP, Mr. Reynolds receives an annual credit of performance-based stock equivalents to a Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan. The value of this account at December 31, 2007 is shown in the "2007 Nonqualified Deferred Compensation Plan" table and the stock equivalent program is further described in the narrative text accompanying that table.*

2 *The amounts reported in this column for each officer were calculated assuming no future service or pay increases. Present values were calculated assuming no pre-retirement mortality or termination. The values under the Retirement Plan and the SERP are the actuarial present values as of December 31, 2007 of the benefits earned as of that date and payable at normal retirement age (age 65 for the Retirement Plan and age 62 for the SERP). Future cash balance interest credits were assumed to average 6.5% annually. The discount assumption is 6.3%, and the post-retirement mortality assumption is based on the 1994 Group Annuity Reserving Table (unisex). An applicable interest rate of 6% is assumed for the purpose of converting annuity benefits to lump sum amounts at retirement. These assumptions are consistent with the ones used for the Retirement Plan and the SERP for financial reporting purposes. In order to determine the change in pension values for the "Summary Compensation" table, the values of the Retirement Plan and the SERP benefits were also calculated as of December 31, 2006 for the benefits earned as of that date. The discount assumption used in that calculation was 5.8%, which is the assumption used for financial reporting purposes for 2006. Other assumptions used to determine the value as of December 31, 2006 were the same as those used for December 31, 2007.*

3 *As described in footnote (2) above, the amounts reported for the SERP in this column are actuarial present values, calculated using the actuarial assumption used for financial reporting purposes. These assumptions are different from those used to calculate the actual amount of benefit payments under the SERP (see text below for a discussion of the actuarial assumptions used to calculate actual payment amounts). For each SERP-eligible Named Executive Officer who was vested in his or her SERP benefit as of December 31, 2007, the following table shows the estimated lump sum amount that would be paid to the Named Executive Officer at age 62 (without discounting to the present), calculated as if such Named Executive Officer had terminated employment on December 31, 2007. For those Named Executive Officers who were not vested in their SERP benefits as of December 31, 2007, the following table reflects the fact that they are not yet vested by showing their age 62 lump sum SERP benefit as $0.*

Executive	Lump Sum	Vested Amount
Bertrand A. Valdman	$ 776,663	$ 776,663
Eric M. Markell	678,005	678,005
Susan McLain	1,831,756	1,831,756
Jennifer L. O'Connor	625,626	--
Kimberly J. Harris	900,255	900,255

Retirement Plan

Under the Retirement Plan, Puget Energy's and PSE's eligible salaried employees, including the Named Executive Officers, accrue benefits in accordance with a cash balance formula, beginning on the later of their date of hire or March 1, 1997. Under this formula, for each calendar year after 1996, age-weighted pay credits are allocated to a bookkeeping account (a "Cash Balance Account") for each participant. The pay credits range from 3% to 8% of eligible compensation. Eligible compensation generally includes base salary and bonuses (other than bonuses paid under the Puget Sound Energy Long Term Incentive Program for Senior Management, signing, retention and similar bonuses), up to the limit imposed by the Internal Revenue Code. For 2007, the Internal Revenue Code compensation limit was $225,000. For 2008, it is $230,000. In addition, as of March 1, 1997, the Cash Balance Account of each participant who was participating in the Retirement Plan on March 1, 1997 was credited with an amount based on the actuarial present value of that participant's accrued benefit, as of February 28, 1997, under the Retirement Plan's previous formula.

Amounts in the Cash Balance Accounts are also credited with interest. The interest crediting rate is 4% per year or such higher amount as PSE may determine. For 2007 and 2008 the annual interest crediting rate is 6.5%.

A participant's Retirement Plan benefit generally vests upon the earlier of the participant's completion of three years of active service with Puget Energy, PSE or their affiliates or attainment of age 65 (the Retirement Plan's normal retirement age). Normal retirement benefit payments begin to a vested participant as of the first day of the month following the later of the participant's termination of employment or attainment of age 65. However, a vested participant may elect to have his or her benefit under the Retirement Plan paid, or commence to be paid, as of the first day of any month commencing after the date on which his or her employment with Puget Energy, PSE and their affiliates terminates. If benefit payments commence prior to the participant's attainment of age 65, then the amount of the monthly payments will be reduced for early commencement to reflect the fact that payments will be made over a longer period of time. This reduction is subsidized — that is, it is less than a pure actuarial reduction. The amount of this reduction is, on average, 0.30% for each of the first 60 months, 0.33% for each of the second 60 months, 0.23% for each of the third 60 months and 0.17% for each of the fourth 60 months that the payment commencement date precedes the participant's 65th birthday. Further reductions apply for each additional month that the payment commencement date precedes the participant's 65th birthday. As of December 31, 2007, all the Named Executive Officers vested in their benefits under the Retirement Plan.

The normal form of benefit payment for unmarried participants is a straight life annuity providing monthly payments for the remainder of the participant's life, with no death benefits. The straight life annuity payable on or after the participant's normal retirement age is actuarially equivalent to the balance in the participant's Cash Balance Account as of the date of distribution. For married participants, the normal form of benefit payment is an actuarially equivalent joint and 50% survivor annuity with a "pop-up" feature providing reduced monthly payments (as compared to the straight life annuity) for the remainder of the participant's life and, upon the participant's death, monthly payments to the participant's surviving spouse for the remainder of the spouse's life in an amount equal to 50% of the amount being paid to the participant. Under the pop-up feature, if the participant's spouse predeceases the participant, the participant's monthly payments increase to the level that would have been provided under the straight life annuity. In addition, the Retirement Plan provides several other annuity payment options and a lump sum payment option that can be elected by participants. All payment options are actuarially equivalent to the straight life annuity. However, in no event will the amount of the lump sum payment be less than the balance in the participant's Cash Balance Account as of the date of distribution (in some instances the amount of the lump sum distribution may be greater than the balance in the Cash Balance Account due to differences in the morality table and interest rates used to calculate actuarial equivalency) birthday. Further reductions apply for each additional month that the payment commencement date precedes the participant's 65th birthday.

If a participant in the cash balance portion of the Retirement Plan dies while employed by the Company, PSE or any of their affiliates, then his or her Retirement Plan benefit will be immediately vested. If a vested participant dies before his or her Retirement Plan benefit is paid, or commences to be paid, then the participant's Retirement Plan benefit will be paid to his or her beneficiary(ies). If a participant dies after his or her Retirement Plan benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the participant.

Supplemental Executive Retirement Plan

The SERP provides a benefit to participating executives that supplements the retirement income provided to such executives by the Retirement Plan. PSE designates which executives are eligible to participate in the SERP. As discussed in the Compensation Discussion and Analysis on page 145, Mr. Valdman, Mr. Markell, Ms. Harris, Ms. O'Connor and Ms. McLain participate in the SERP.

A participant's SERP benefit generally vests upon the participant's completion of five years of participation in the SERP while employed by Puget Energy, PSE or any of their affiliates. Mr. Markell, Ms. Harris and Ms. McLain are vested in SERP benefit based on their years of service. By agreement with PSE, Mr. Valdman became vested in his SERP benefit on the date he was hired. The monthly benefit payable under the SERP to a vested participant (calculated in the form of a straight life annuity payable for the participant's lifetime commencing at the later of the participant's date of termination or attainment of age 62) is equal to (1) below minus the sum of (2) and (3) below:

(1) One-twelfth (1/12) of the participant's highest average earnings times the participant's years of credited service (not in excess of 15) times 3--1/3%. For purposes of the SERP, "highest average earnings" means the average of the participant's highest three calendar years of earnings. The three calendar years do not have to be consecutive, but they must be among the last five calendar years completed by the participant prior to his or her termination. "Earnings" for this purpose include base salary and annual bonus, but do not include long-term incentive compensation. A participant will receive one "year of credited service" for each consecutive 12-month period he or she is employed by Puget Energy, PSE or their affiliates. If a participant becomes entitled to disability benefits under PSE's long-term disability plan, then the participant's highest average earnings will be determined as of the date the participant became disabled, but the participant will continue to accrue years of credited service until he or she begins to receive SERP benefits.

(2) The monthly amount payable (or that would be payable) under the Retirement Plan to the participant in the form of a straight life annuity commencing as of the first day of the month following the later of the participant's date of termination or attainment of age 62.

(3) The actuarially equivalent monthly amount payable (or that would be payable) to the participant as of the first day of the month following the later of the participant's date of termination or attainment of age 62 from any pension-type rollover accounts (including the Annual Cash Balance Restoration Account) within the Deferred Compensation Plan. These accounts are described in more detail in the "2007 Nonqualified Deferred Compensation" section.

Normal retirement benefits under the SERP generally are paid or commence to be paid as of the first day of the month following the later of the participant's termination of employment or attainment of age 62. Except as provided below, SERP benefits are normally paid in a lump sum that is equal to the actuarial present value of the monthly straight life annuity benefit. A participant may elect to have this lump sum transferred to the Deferred Compensation Plan, rather than paid directly to the participant, after which it will be paid in accordance with the provisions of the Deferred Compensation Plan. In lieu of the normal form of payment, a participant may elect to receive his or her SERP benefit in the form of monthly installment payments over a period of two to 20 years, in a straight life annuity or in a joint and survivor annuity with a 100%, 50% or 25% survivor benefit. All payment options are actuarially equivalent to the straight life annuity. SERP benefits that were vested as of December 31, 2004 (Pre-2005 SERP Benefits) are normally paid in the form of a straight life annuity for single participants and in the form of an actuarially equivalent joint and 50% surviving spouse annuity for married participants. However, participants can elect any of the payment options described above for their Pre-2005 SERP Benefits. Of the Named Executive Officers, only Ms. McLain has Pre-2005 SERP Benefits. Mr. Markell is the only Named Executive Officers eligible for early retirement benefit payments under the SERP. Payments to the participant following termination of employment of SERP benefits other than Pre-2005 SERP Benefits are generally delayed for six months in accordance with the requirements of Section 409A of the Internal Revenue Code.

If a participant dies while employed by Puget Energy, PSE or any of their affiliates or after becoming vested in his or her SERP benefit, but before his or her SERP benefit has commenced to be paid, then the participant's surviving spouse will receive a lump sum benefit equal to the actuarial equivalent of the survivor benefit such spouse would have received under the joint and 50% surviving spouse annuity option. This amount will be calculated assuming the participant would have commenced benefit payments in that form on the first day of the month following the later of his death or attainment of age 62. The lump sum benefit will then be reduced by one-third of one percent (1/3%) for each month by which the participant's date of death preceded what would have been his 62nd birthday. Distribution will be made to the participant's surviving spouse as soon as administratively practicable after the participant's death. If the participant is not married, then no death benefit will be paid. If a participant dies after his or her SERP benefit has commenced to be paid, then any death benefit will be governed by the form of payment elected by the participant.

2007 Nonqualified Deferred Compensation

The following table provides information for each of the Named Executive Officers regarding aggregate executive and Company contributions and aggregate earnings for 2007 and year-end account balances under the Deferred Compensation Plan.

Name	Executive Contributions in Last FY[1]	Registrant Contributions in Last FY[2]	Aggregate Earnings in Last FY[3]	Aggregate Withdrawals/ Distributions[4]	Aggregate Balance at Last FYE[5]
Stephen P. Reynolds	$97,265	$306,274	$231,201	$70,150	$2,304,489
Bertrand A. Valdman	32,797	21,936	8,910	--	160,054
Eric M. Markell	17,755	13,250	13,536	--	187,794
Susan McLain	41,131	13,516	49,238	--	553,261
Jennifer L. O'Connor	10,617	10,617	13,592	--	249,566
Kimberly J. Harris	--	--	19,937	--	187,511

1 *The amount in this column for each executive reflects elective deferrals by the officer of salary, annual incentive compensation or vested performance shares paid in 2007, the following amounts of salary: Mr. Reynolds, $53,258; Mr. Valdman, $24,967; Mr. Markell, $17,755; Ms. McLain, $32,073; Ms. O'Connor, $10,617; and Ms. Harris, $0. The following amounts of incentive compensation: Mr. Reynolds, $44,007; Mr. Valdman, $7,830; Mr. Markell, $0; Ms. McLain, $9,058; Ms. O'Connor, $0, and Ms. Harris, $0.*

2 *The amount reported in this column for each executive reflects contributions by PSE consisting of the Annual Investment Plan Restoration Amount and Annual Cash Balance Restoration Amount. For Mr. Reynolds, the amount also includes $234,617 in value of performance-based stock equivalents credited in the Deferred Compensation Plan's Performance-Based Retirement Equivalent Stock Account and calculated pursuant to his employment agreement based on the closing price of Puget Energy stock on January 8, 2007 of $24.76. These amounts are also included in the total amounts shown in the All Other Compensation column of the "Summary Compensation" table.*

3 *The amount in this column for each officer reflects dividends on deferred stock units and the change in value of other investment tracking funds.*

4 *The amount in this column for Mr. Reynolds reflects a scheduled interim payment pursuant to the terms of the Deferred Compensation Plan.*

5 *The amount reported in this column for each executive includes stock unit values based on the closing price of Puget Energy stock on December 31, 2007 of $27.43. The aggregate balance for Mr. Reynolds includes $236,888 of unvested performance-based stock equivalents credited in the Deferred Compensation Plan's Performance-Based Retirement Equivalent Stock Account. The following amounts of salary from 2006 are included: Mr. Reynolds, $56,592; Mr. Valdman, $26,558; Mr. Markell, $18,913; Ms. McLain, $27,421; Ms. O'Connor, $21,573; and Ms. Harris, $0. The following amounts of incentive compensation from 2006 are included: Mr. Reynolds, $53,200; Mr. Valdman, $10,013; Mr. Markell, $0; Ms. McLain, $5,138; Ms. O'Connor, $475; and Ms. Harris, $0. The following amounts of registrant contributions from 2006 are included: Mr. Reynolds, $249,815; Mr. Valdman, $26,195; Mr. Markell, $14,020; Ms. McLain, $15,111; and Ms. Harris, $0.*

Deferred Compensation Plan

The Named Executive Officers are eligible to participate in the PSE Deferred Compensation Plan.

Participants may defer up to 100% of base salary, annual incentive compensation and vested performance shares. In addition, each year, participants are eligible to receive Company contributions to restore benefits not available to them under PSE's tax-qualified plans due to limitations imposed by the Internal Revenue Code. The Annual Investment Plan Restoration Amount equals the additional matching contribution under the 401(k) plan that would have been credited to a participant's 401(k) plan account if the Internal Revenue Code limitations were not in place and if deferrals under the Deferred Compensation Plan were instead made to the 401(k) plan. The Annual Cash Balance Restoration Amount equals the actuarial equivalent of any reductions in a participant's accrued benefit under the Retirement Plan due to Internal Revenue Code limitations or as a result of deferrals under the Deferred Compensation Plan. A participant must generally be employed on the last day of the year to receive these Company contributions, unless he or she retires or dies during the year in which case PSE will contribute a prorated amount.

In lieu of participation in the SERP, Mr. Reynolds receives an annual credit of performance-based stock equivalents to his Deferred Compensation Plan's Performance-Based Retirement Equivalent Stock Account each January commencing on January 1, 2003. The number of stock equivalents is determined by calculating the number of shares obtained by taking 15% of Mr. Reynolds' base salary and annual bonus for the preceding year and dividing that amount by the average per-share closing price of Puget Energy stock on the last day of October, November and December of the preceding year. The stock equivalents are entitled to dividend equivalents equal to all dividends declared on Puget Energy stock, which are then credited to the Performance-Based Retirement Equivalent Stock Account as additional stock equivalents. The stock equivalents vest over seven years from January 1, 2002 at 15% per year for the first six years, with the balance vesting on May 6, 2008.

Participants choose how to credit deferred amounts among four investment tracking funds. The tracking funds mirror performance in major asset classes of bonds, stocks, Puget Energy stock, and interest crediting. The tracking funds differ from the investment funds offered in PSE's 401(k) plan. The 2007 calendar year returns of these tracking funds were:

Vanguard Total Bond Market Index	7.05%
Vanguard 500 Index	5.39%
Puget Energy Stock	11.90%
Interest Crediting Fund	6.20%

Participants may change how deferrals are allocated to the tracking funds at any time, subject to insider trading rules and other Deferred Compensation Plan restrictions that limit the transfer of funds into or out of Puget Energy stock. Changes generally become effective as of the first trading day of the following calendar quarter.

Participants generally may choose how and when to receive payments under the Deferred Compensation Plan. There are three types of in-service withdrawals. First, a participant may choose an interim payment of deferred based salary, annual bonus or vested performance shares by electing a payment date at the time of his or her deferral election. The interim payment cannot occur earlier than the third year following the year of the deferral election. Second, an in-service withdrawal may also be made to a participant upon a qualifying hardship event and demonstrated need. Third, only with respect to amounts deferred and vested prior to 2005, the participant may elect an in-service withdrawal for any reason by paying a 10% penalty. Payments upon termination of employment depend on whether the participant is then eligible for retirement. If the participant's termination occurs prior to his or her retirement date (generally the earlier of attaining age 62 or age 55 with five years of credited service), the participant will receive a lump sum payment of his or her vested account balance. If the participant's termination occurs after his or her retirement date, of the amounts that are initially deferred or that become vested after December 31, 2004 the participant may choose to receive payments in a lump sum or via one of several installment options based on the participant's vested account balances. Mr. Reynolds and Mr. Markell are the only Named Executive Officers currently retirement eligible. Payments to the participant following a termination or retirement date are generally delayed for six months in accordance with the requirements of Section 409A of the Internal Revenue Code, except distributions of Puget Energy stock take place in the following January (if later) and each January thereafter if applicable.

Potential Payments Upon Termination or Change in Control

The "Estimated Potential Incremental Payments Upon Termination or Change in Control" table reflects the estimated amount of incremental compensation payable to each of the Named Executive Officers following an executive's termination of employment in the event of (i) an involuntary termination without cause or for good reason that is not in connection with a change in control; (ii) a change in control; (iii) an involuntary termination without cause or for good reason in connection with a change in control; (iv) retirement; (v) disability; or (vi) death. The amounts shown assume that the termination was effective as of December 31, 2007 and that the price of Puget Energy stock upon which certain of the calculations are made was the closing price of $27.43 on December 31, 2007. These amounts are estimates of the incremental amounts that would be paid out to the executive upon such terminations. The actual amounts to be paid out can only be determined at the time of the executive's termination. The Merger proxy statement describes the anticipated amount of such benefits that would be provided upon occurrence of the Merger.

Payments Made Upon Termination

Regardless of the manner in which an executive's employment terminates, the executive is entitled to receive amounts earned during the term of employment. These amounts, which are not included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table, include:

- Amounts contributed by the executive under the PSE Investment Plan and Deferred Compensation Plan; and
- Amounts accrued and vested through the PSE Retirement Plan and SERP.

Payments Made Upon Retirement

In the event of the retirement of a Named Executive Officer, in addition to the items identified above, the executive will receive the estimated incremental benefits reflected in the table below as a result of the following:

- Pro-rata payment of Performance Awards, which will be paid based on the value at the end of the year pro-rated through the month of retirement based on Puget Energy's relative Total Shareholder Return as of the quarter-end of the quarter prior to retirement; and
- Named Executive Officers also receive a pro-rata payment of annual incentive awards, which is paid pro-rata to the extent earned in the year following retirement, provided the executive worked a minimum of 520 hours during the year. No estimated amounts are shown in the table below for annual incentive compensation earned in 2007.

Payments Made Upon Disability or Death

In the event of the disability or death of a Named Executive Officer, in addition to the benefits listed above, the executive will receive benefits under the PSE disability plan or life insurance plan available generally to all salaried employees. These disability and life insurance amounts are not reflected in the table below. The executive will also receive supplemental disability and life insurance. The disability coverage is extended to include base salary and target incentive pay. Life insurance benefit is provided at two times base salary and target annual incentive bonus if the executive dies while employed by PSE with a reduction for amounts payable under the applicable group policy, or a single sum amount equal to the actuarial equivalent of the combined annual annuity benefit if the executive dies after retiring.

Payments Made Pursuant to Employment and Change in Control Agreements

Puget Energy and Puget Sound Energy (together, the "Company") entered into an employment agreement with Mr. Reynolds as of January 1, 2002 to secure his services as Chief Executive Officer and President. The agreement has an initial term of three years after which time it will be automatically renewed for one-year terms unless notice of termination is given by either party at least 180 days prior to the expiration of the then current term. Pursuant to the agreement, Mr. Reynolds was appointed to the Board of Directors and the Board will recommend him for reelection during the term of the agreement. The agreement was amended on May 10, 2005 and February 9, 2006. The agreement provides for the following benefits, the estimated value of which is included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

If at any time the Company terminates Mr. Reynolds' employment without cause, or Mr. Reynolds terminates his employment with good reason, Mr. Reynolds will then receive the following severance benefits:

- An amount equal to two times his then current annual base salary and target annual incentive bonus;
- Accelerated two years of vesting in his Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan; and
- Accelerated vesting of stock options granted under the agreement.

If a change in control occurs during the term of the employment agreement, Mr. Reynolds will receive the following compensation and benefits at the time of the change in control:

- An amount equal to three times his then current base salary and target annual incentive bonus;
- Accelerated vesting of all outstanding equity awards;
- Accelerated vesting of his Performance-Based Retirement Equivalent Stock Account in the Deferred Compensation Plan;
- Continued medical, dental and insurance benefits for a period of three years or until he obtains similar coverage through another employer; and
- A cash payment equal to any excise taxes imposed by Section 4999 of the Internal Revenue Code due to payments received under the employment agreement or any other payment or benefit from the Company, plus the income taxes payable by him resulting from this cash payment.

The employment agreement contains a noncompetition covenant. Mr. Reynolds commits that for a period of two years following his voluntary termination, without good reason, he will not perform services for any person or entity selling or distributing electric power or natural gas in Washington, Oregon or Idaho, unless the Company consents in writing. The Company may enforce this covenant through injunctive relief or other appropriate remedies.

The employment agreement also contains an indemnification clause in favor of Mr. Reynolds. The Company commits to defend, indemnify and hold harmless Mr. Reynolds from all liabilities in connection with his service. As part of that commitment, the Company will continue to cover him under the Company's directors' and officers' liability insurance for six years following his termination of employment.

Under the employment agreement, "change in control," "good reason," and "cause" have the following meanings:

> *Change in Control* means any one of the following events: (i) any person becomes the beneficial owner of more than 30% of Puget Energy's common stock or voting securities, with certain exceptions; (ii) the incumbent directors (including those nominees subsequently nominated or appointed by incumbent directors) cease for any reason to constitute at least a majority of the Board of Directors; and (iii) consummation of a reorganization, merger, consolidation or other business combination involving Puget Energy, or a sale of substantially all of the assets of either of the Puget Energy or PSE, unless (x) after such transaction the beneficial shareholders of the outstanding Puget Energy common stock and voting securities entitled to vote on director elections immediately prior to the transaction retain more than 60% of such common stock and voting securities; (y) no beneficial shareholder owns 30% or more of the then outstanding common stock or voting securities entitled to vote on director elections, and (z) at least a majority of the directors resulting from such transaction were incumbent directors at the time of executing the initial agreement providing for such transaction.

> *Good Reason* includes the following actions by the Company: (i) assigning duties inconsistent with, or taking actions in diminution of, his position (including status, offices, titles and reporting requirements), authority, duties or responsibility under the employment agreement; (ii) failing to comply with the provisions of the employment agreement; (iii) requiring that he be based at any location other than its corporate headquarters or relocating the corporate headquarters more than 25 miles from Bellevue, Washington; and (iv) failing to assign the employment agreement to a successor or the successor failing to assume and be bound by it explicitly. Good Reason is triggered on a reasonable determination by Mr. Reynolds that any of the above events has occurred.

> *Cause* means (i) the willful and continued failure to substantially perform Mr. Reynolds' duties or (ii) the willful engaging in gross misconduct materially and demonstrably injurious to the Company. Cause does not include any act or omission believed to be in good faith and in the best interests of the Company.

In February 2006 PSE entered into amended change in control agreements with each of Mr. Valdman, Ms. O'Connor, Ms. McLain and Mr. Markell (the "Executives"), the terms of which are the same for all four Executives. If a change in control occurs, for a period of two years following the change in control of PSE (the "employment period"), the Executives will receive continued base salary, annual incentive bonus and other incentive, savings and retirement plans and programs applicable to PSE peer executives at comparable levels to those prior to the change in control. These benefits are not reflected in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

At the time of the change in control, the Executives will receive the following benefits, the estimated value of which is included in the "Estimated Potential Incremental Payments Upon Termination or Change in Control" table.

- Accelerated vesting in the SERP.
- Accelerated vesting of any outstanding equity awards.
- A cash payment in consideration of all outstanding performance awards equal to the product of a deemed stock price (calculated based on the greater of (i) the average last sales price of Puget Energy stock on the NYSE in each of the 20 days preceding the change in control, and (ii) the highest price per share actually paid in connection with the change in control) multiplied by a deemed number of shares related to the performance awards (calculated based on the greater of (x) the total shares payable at the target award level on full vesting of each such award, and (y) the shares payable on full vesting of each such award if PSE achieved for each award cycle the same percentile ranking against its designated universe of companies which the PSE had achieved for the applicable cycle but ending with the fiscal quarter immediately prior to the change in control).

After a change in control, if at any time during the employment period PSE terminates an Executive's employment without cause or due to disability or death, or the Executive terminates his or her employment with good reason, PSE will pay the Executive:

- A lump sum in cash equal to (i) any accrued but unpaid base salary, (ii) a pro rata portion of the Executive's annual incentive bonus for the year, (iii) any accrued paid time off pay, and (iv) a severance benefit equal to three times the sum of the annual base salary and the annual incentive bonus for which he or she was eligible for the year in which the date of termination occurs, unless an acceptable release is not executed by the Executive in which case the severance benefit will equal one times such sum.
- A separate lump-sum supplemental retirement benefit equal to the difference between (x) the actuarial equivalent of the amount he or she would have received under the Retirement Plan and the SERP had his or her employment continued until the end of the employment period, and (y) the actuarial equivalent of the amount he or she actually receives or is entitled to receive under the Retirement Plan and SERP.
- Continued welfare and fringe benefits described above for the Executive and the Executive's family at least equal to those that would have been provided if the Executive's employment had not terminated through the remainder of the employment period, except that if the Executive becomes re-employed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits received under the amended agreement will be secondary to those provided by the other employer.

If any payments paid or payable under the amended change in control agreement or otherwise are characterized as "excess parachute payments" within the meaning of Section 280G the Internal Revenue Code, then PSE will make cash payment to or on behalf of the Executive equal to any excise taxes imposed by Section 4999 of the Internal Revenue Code due to payments received under the amended agreement or any other payment or benefit from the Company, plus the income taxes payable by him or her resulting from this cash payment.

The amended change in control agreements contain a confidentiality clause. The Executives must keep confidential all secret or confidential information, knowledge or data relating to the Company and its affiliates obtained during their employment. The Executives may not disclose any such information, knowledge or data after their respective terminations of employment unless PSE consents in writing or as required by law. PSE cannot withhold or defer the payment of any amounts otherwise due under the agreement based on an Executive's asserted violation of the confidentiality clause.

Under the amended change in control agreements, "change in control" has the same meaning as under Mr. Reynolds' employment agreement. "Good reason" and "cause" have the following meanings:

Good reason means (i) the assignment of any duties inconsistent with, or taking action in diminution of, the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities; (ii) any failure by PSE to comply with the provisions of the agreement regarding compensation during the employment period; (iii) requiring the Executive to be based at any location other than the Seattle/Bellevue metropolitan area; (iv) any purported termination of the Executive's employment other than as expressly permitted by the amended agreement; and

(v) PSE's failure to assign the amended agreement to a successor to PSE or failure of a successor to PSE to explicitly assume and agree to be bound by the amended agreement.

Cause means (i) the willful and continued failure to substantially perform the Executive's duties or (ii) the willful engaging in gross misconduct materially and demonstrably injurious to PSE. Cause does not include any act or omission believed to be in good faith and in the best interests of PSE.

The table below presents estimated incremental compensation payable to each of the Named Executive Officers as described above. The incremental compensation is presented in the following benefit categories:

- Cash severance: multiple of salary and target annual incentive; does not reflect salary paid or annual incentive compensation earned in 2007
- Stock options: in-the-money value, as of December 31, 2007 of unvested stock options that would vest
- Service-based stock awards: market value, as of December 31, 2007 of unvested equity awards that would vest; includes Restricted Stock and Restricted Stock Units
- Performance-Based Stock Awards: market value, as of December 31, 2007 of unvested performance-based restricted stock awards that would vest
- Performance Shares: amount calculated in accordance with formula in the amended change in control agreements
- Performance-Based Retirement Equivalent Stock Account: market value, as of December 31, 2007 of unvested portion of account that would vest
- SERP: estimated actuarial value of the Executive's supplemental pension benefits under the amended change in control agreements
- Health and welfare benefits: estimated value of benefits continued following the termination
- Perquisites, consisting of estimated value of continuation of financial planning and, for Mr. Valdman, relocation allowance
- Estimated value of excise tax gross-up

Estimated Potential Incremental Payments Upon Termination or Change in Control

	Involuntary Termination w/o Cause or for Good Reason	Upon Change in Control	After Change in Control Involuntary Termination w/o Cause or for Good Reason	Retirement	Disability	Death
Stephen P. Reynolds						
Cash Severance (salary and/or annual incentive)	$2,960,000	$ 4,440,000	$ 4,440,000	$ --	$ --	$ --
Stock Options (vesting accelerated)	--	--	--	--	--	--
Service-Based Stock Awards (vesting accelerated)	--	1,097,200	1,097,200	--	--	--
Performance-Based Stock Awards (vesting accelerated)	--	1,977,593	1,977,593	--	--	--
Performance Shares (vesting accelerated)	--	3,897,708	3,897,708	969,912	969,912	969,912
Performance-Based Retirement Equivalent Stock Account (vesting accelerated)	236,888	95,445	95,445	--	--	--
Health and Welfare Benefits (continuation)	--	--	23,400	--	--	--
Supplemental Life Insurance	--	--	--	--	--	2,280,000
Perquisites	--	--	--	--	--	--
Excise Tax Gross-Up	--	3,312,157	3,322,903	--	--	--
Total Estimated Incremental Value	$3,196,888	$14,820,103	$14,854,249	$ 969,912	$ 969,912	$3,249,912
Bertrand A. Valdman						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,878,408	$ --	$ --	$ --
Service-Based Stock Awards (vesting accelerated)	n/a	54,860	54,860	--	--	--
Performance-Based Stock Awards (vesting accelerated)	n/a	452,705	452,705	--	--	--
Performance Shares (vesting accelerated)	n/a	860,397	860,397	215,553	215,553	215,553
SERP (additional years of credited service)[1]	--	--	509,869	--	n/a	--
Health and Welfare Benefits (continuation)	n/a	--	27,840	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	975,000
Perquisites	n/a	--	19,000	--	--	--
Excise Tax Gross-Up	n/a	--	1,237,130	--	--	--
Total Estimated Incremental Value	$ n/a	$ 1,367,962	$ 5,040,209	$ 215,553	$ 215,553	$1,190,553
Eric M. Markell						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,440,000	$ --	$ --	$ --
Performance-Based Stock Awards (vesting accelerated)	n/a	287,274	287,274	--	--	--
Performance Shares (vesting accelerated)	n/a	546,099	546,099	136,919	136,919	136,919
SERP (additional years of credited service)[1]	--	--	450,937	n/a	n/a	n/a
Health and Welfare Benefits (continuation)	n/a	--	27,840	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	975,000
Perquisites	n/a	--	10,000	--	--	--
Excise Tax Gross-Up	n/a	--	1,033,250	--	--	--
Total Estimated Incremental Value	$ n/a	$ 833,373	$ 3,795,400	$ 136,919	$ 136,919	$1,111,919
Susan McLain						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,247,324	$ --	$ --	$ --
Performance-Based Stock Awards (vesting accelerated)	n/a	289,908	289,908	--	--	--
Performance Shares (vesting accelerated)	n/a	551,649	551,649	138,804	138,804	138,804
SERP (additional years of credited service)[1]	--	--	117,800	--	n/a	--
Health and Welfare Benefits (continuation)	n/a	--	15,600	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	518,700
Perquisites	n/a	--	10,000	--	--	--
Excise Tax Gross-Up	n/a	--	776,036	--	--	--
Total Estimated Incremental Value	$ n/a	$ 841,557	$ 3,008,317	$ 138,804	$ 138,804	$ 657,504
Jennifer L. O'Connor						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,350,998	$ --	$ --	$ --
Performance-Based Stock Awards (vesting accelerated)	n/a	339,583	339,583	--	--	--
Performance Shares (vesting accelerated)	n/a	592,027	592,027	148,101	148,101	148,101
SERP (additional years of credited service)[1]	n/a	625,626	1,040,497	n/a	n/a	n/a
Health and Welfare Benefits (continuation)	n/a	--	27,840	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	735,000
Perquisites	n/a	--	10,000	--	--	--
Excise Tax Gross-Up	n/a	247,511	983,311	--	--	--
Total Estimated Incremental Value	$ n/a	$ 1,804,747	$ 4,344,256	$ 148,101	$ 148,101	$ 883,101
Kimberly Harris						
Cash Severance (salary and/or annual incentive)	$ n/a	$ --	$ 1,440,000	$ --	$ --	$ --
Performance-Based Stock Awards (vesting accelerated)	n/a	288,317	288,317	--	--	--
Performance Shares (vesting accelerated)	n/a	547,306	547,306	136,447	136,447	136,447
SERP (additional years of credited service)[1]	--	--	540,633	n/a	n/a	n/a
Health and Welfare Benefits (continuation)	n/a	--	15,600	--	--	--
Supplemental Life Insurance	n/a	--	--	--	--	975,000
Perquisites	n/a	--	10,000	--	--	--
Excise Tax Gross-Up	n/a	--	949,906	--	--	--
Total Estimated Incremental Value	$ n/a	$ 835,623	$ 3,791,762	$ 136,447	$ 136,447	$1,111,447

1 *SERP values are shown as the estimated incremental value that the Named Executive Officer would receive at age 62 as a result of the termination event shown in the column, relative to the vested benefit as of December 31, 2007. These values are based on interest rate and mortality rate assumptions consistent with those used in the Company's financial statements.*

DIRECTOR COMPENSATION FOR FISCAL YEAR 2007

The following table sets forth information regarding compensation for each of the Company's nonemployee directors for 2007. As described in further detail below, the Company's nonemployee director compensation program in 2007 consisted of quarterly retainer fees of $20,000, payable in the form of Puget Energy shares until a director owns a number of Puget Energy shares equal in value to two years of retainer fees. Additional quarterly retainer amounts associated with serving as lead director, chairing Board committees and serving on the Audit Committee, and meeting fees are paid in cash. Directors may defer their cash or stock fees into deferred stock units.

Name	Fees Earned or Paid in Cash[1]	Stock Awards[2]	Nonqualified Deferred Compensation Earnings[3]	Total
William S. Ayer	$ 27,750	$ 76,667	$ —	$ 104,417
Phyllis J. Campbell	62,125	57,500	597	120,222
Craig W. Cole	31,525	76,667	329	108,521
Stephen E. Frank	46,625	76,667	—	123,292
Tomio Moriguchi	25,525	76,667	—	102,192
Dr. Kenneth P. Mortimer	56,682	51,110	—	107,792
Sally G. Narodick	64,282	51,110	—	115,392
Herbert B. Simon	27,750	76,667	—	104,417
George W. Watson	29,525	76,667	—	106,192

1 *The amounts in this column reflect director compensation earned and paid in cash, including amounts deferred under our Deferred Compensation Plan for Nonemployee Directors. Mr. Watson received 1,145 deferred stock units from deferrals of cash compensation totaling $29,525 in 2007.*

2 *The amounts in this column reflect the dollar amount the Company recognized for financial statement reporting purposes for 2007 in accordance with SFAS No. 123R for stock awards granted in 2007. The SFAS 123R fair value for these awards is equal to the fair market value of the underlying Puget Energy stock on the date of grant.*

3 *Represents earnings accrued to deferred compensation considered to be above market.*

Nonemployee Director Compensation Program. The Board believes that the level of nonemployee director compensation should be based on Board and committee responsibilities and be competitive with comparable companies. In addition, the Board believes that a significant portion of nonemployee director compensation should align director interests with the long-term interests of shareholders.

The 2007 compensation program for nonemployee directors was as follows:

- A base cash quarterly retainer fee of $20,000 payable in Puget Energy stock until a director owns a number of Puget Energy shares equal in value to two years of retainer fees.[1]
- $1,600 for attendance at each Board and committee meeting, and $800 for each telephonic meeting lasting 60 minutes or less, for the first two months of 2007 and $1,600 and $800, respectively, thereafter.[2]

Nonemployee directors were paid the following additional cash quarterly retainer fees in 2007:

- Lead independent director, $3,750[3]
- Chair of the Audit Committee, $2,500
- Chair of the Compensation and Leadership Development Committee, $2,000
- Chair of the Governance and Public Affairs Committees, $1,500
- Each member of the Audit Committee other than the chair, $1,000

1 *Prior to March 1, the base cash quarterly retainer fee was $15,000, at least two-thirds of which was payable in Puget Energy stock.*

2 *Prior to March 1, the fee for attendance at each Board and committee meeting was $1,250 and the fee for each telephonic meeting lasting 60 minutes or less was $625.*

3 *Prior to March 1, the lead independent director was paid a cash quarterly retainer fee of $5,000.*

To facilitate the stock ownership guidelines described below, 100% of the quarterly retainer fee is paid in the form of Puget Energy shares until a director owns a number of Puget Energy shares equal in value to two years of retainer fees.

After meeting this ownership requirement, a portion of the base quarterly retainer for a fiscal quarter is payable in shares of Puget Energy stock. Under the terms of our Nonemployee Director Plan and Board policies as currently in effect, the number of shares is determined by dividing two-thirds of the base quarterly retainer by the fair market value of Puget Energy stock for the last business day of a fiscal quarter. For this purpose, fair market value for a single trading day is the average of the high and low trading prices for Puget Energy stock as reported by the NYSE.

All quarterly retainer and meeting attendance fees are paid on the last business day of March, June, September and December. Nonemployee directors are reimbursed for actual travel and out-of-pocket expenses incurred in connection with their services. Directors who also serve as employees of the Company do not receive compensation for their service on the Board or any committees.

Nonemployee directors are eligible to participate in our matching gift program on the same terms as all Puget Energy employees. Under this program, we will match up to a total of $300 a year in contributions by a director to non-profit organizations with an IRS 501(c)(3) tax exempt status that are located in and serve the people of PSE's service territory in Washington State.

Deferral of Compensation. Nonemployee directors may defer receipt of all or a part of their quarterly retainer fees that are required to be paid in Puget Energy stock into unfunded deferred stock unit accounts under our Nonemployee Director Plan. Deferred stock units earn the equivalent of dividends, which are credited as additional deferred stock units. Nonemployee directors do not have the right to vote or transfer the deferred stock units. Deferred stock units will be distributed as shares of Puget Energy stock after retirement or other termination of Board service.

Nonemployee directors may also elect to defer all or a part of their fees payable in cash under our Deferred Compensation Plan for Nonemployee Directors. Nonemployee directors may allocate these deferrals into one or more "measurement funds," which currently include an interest crediting fund, an equity index fund, a bond index fund and a Puget Energy stock fund. Nonemployee directors are permitted to make changes in measurement fund allocations quarterly. Amounts allocated to the Puget Energy stock fund are treated as deferred stock units that will earn the equivalent of dividends, which are credited as additional deferred stock units. Nonemployee directors do not have the right to vote or transfer the deferred stock units. Amounts deferred will be paid at the time elected by the nonemployee director, which must be at least three years after the date of deferral. Amounts allocated to the Puget Energy stock fund are payable only in Puget Energy stock. Other accounts are payable in cash.

Director Compensation Review Practices. The Governance and Public Affairs Committee is responsible for annually reviewing the Company's nonemployee director compensation practices in relation to comparable companies. Any changes to be made to nonemployee director compensation practices must be recommended by the Governance and Public Affairs Committee for approval by the full Board.

Director Stock Ownership Guidelines. The Board believes that nonemployee directors should have a financial stake in the Company. The Board has adopted stock ownership guidelines for nonemployee directors. The guidelines call for the Company to pay the base quarterly retainer in the form of Puget Energy stock until a director owns shares equal in value to the ownership target. Directors and officers of the Company are not allowed to own derivatives of Puget Energy stock, nor are they allowed to own shares in margin accounts.

PUGET SOUND ENERGY

The information called for in this item 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

BENEFICIAL OWNERSHIP

As of December 31, 2007, all of the issued and outstanding shares of PSE's common stock were held beneficially and of record by Puget Energy.

SECURITY OWNERSHIP OF DIRECTORS, EXECUTIVE OFFICERS AND CERTAIN BENEFICIAL OWNERS

The following table shows the number of shares of common stock beneficially owned as of February 15, 2008 by each director, by each executive officer named in the Summary Compensation Table in Item 11 of Part III in this report, by the directors and executive officers of the Company as a group and by each person or group that we know owns more than 5% of our common stock. We consider executive officers of PSE to be executive officers of the Company. No director or executive officer owns more than 1% of the outstanding shares of common stock. Puget Holdings LLC and its affiliates beneficially own approximately 9.6%, Franklin Resources, Inc. and its affiliates beneficially own approximately 8.6% of our common stock. Tradewinds Global Investors LLC beneficially owns approximately 6.5% of our common stock. Percentage of beneficial ownership is based on 129,678,489 shares outstanding as of February 15, 2008.

BENEFICIAL OWNERSHIP TABLE

Name	Number of Beneficially Owned Shares	Number of Share Interests Held [1]
William S. Ayer	--	8,782
Phyllis J. Campbell	1,000	18,253
Craig W. Cole	8,701	11,062
Stephen E. Frank	--	13,083
Tomio Moriguchi	1,571	23,793
Kenneth P. Mortimer	2,852	6,650
Sally G. Narodick	2,272	13,740
Herbert B. Simon	--	5,271
Stephen P. Reynolds	450,507 [2]	74,160
George W. Watson	--	5,886
Eric M. Markell	23,940	2,467
Susan McLain	28,948 [3]	14,194
Jennifer L. O'Connor	20,821	--
Bertrand A. Valdman	38,039 [3]	1,275
All directors and executive officers, including named executive officers, as a group (21 persons)	682,517	208,867
Puget Holdings LLC and affiliates	12,500,000 [4]	
Franklin Resources, Inc. and affiliates	11,092,300 [5]	--
Tradewinds Global Investors, LLC	8,392,505 [6]	

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1 *Includes deferred stock units held in the Company Nonemployee Director Stock Plan and the PSE Deferred Compensation Plans.*

2 *Includes 92,096 shares of restricted stock, 300,000 shares of common stock subject to stock options that are currently exercisable and 950 shares held by Mr. Reynolds's wife.*

3 *Includes shares held under the PSE Investment Plan for Employees (401(k) Plan).*

4 *Information presented above and in this footnote is based on a Schedule 13D filed on December 13, 2007 (the "Schedule 13D") by Puget Holdings LLC ("Parent"), Macquarie Infrastructure Partners A, L.P. ("MIP A"), Macquarie Infrastructure Partners International, L.P. ("MIP I"), Macquarie Infrastructure Partners Canada, L.P. ("MIP C"), Macquarie FSS Infrastructure Trust ("MFIT"), Padua MG Holdings Inc. ("PMGH"), CPP Investment Board (USRE II) Inc. ("USRE"), Padua Investment Trust ("PIT"), PIP2PX (Pad) Ltd. ("PIP2PX") and PIP2GV (Pad) Ltd. ("PIP2GV") and together with all the preceding entities other than the Parent, the "Purchasers"). The Purchasers are the direct or indirect owners of the Parent and severally acquired an aggregate of 12,500,000 shares of common stock of Puget Energy on December 3, 2007. Although the Parent does not own any shares of Puget Energy directly, the Parent and the Purchasers may be deemed to be members of a "group," within the meaning of Section 13(d)(3) of the Securities Exchange Act of 1934, as amended. Accordingly, each such entity may be deemed to beneficially own and have shared voting and dispositive power over the 12,500,000 shares of Puget Energy common stock that are collectively owned by the Purchasers. However, each of the Parent and the Purchasers expressly disclaims beneficial ownership of such shares of common stock other than those shares held directly by such entity. According to the Schedule 13D, as of December 3, 2007:*

- *MIP A held 1,753,788 of the shares, over all of which MIP A has dispositive power and voting power. The address of the principal office of MIP A, as well as the Parent, MIP I and MIP C, is 125 West 55th Street, Level 22, New York, NY 10019.*
- *MIP I held 1,830,864 of the shares, over all of which MIP I has dispositive power and voting power.*
- *MIP C held 393,158 of the shares, over all of which MIP C has dispositive power and voting power.*
- *MFIT held 465,404 of the shares, over all of which MFIT has dispositive power and voting power. Its address of the principal office is Level 11, 1 Martin Place, Sydney, Australia NSW 2000.*
- *PMGH held 1,988,905 of the shares, over all of which PMGH has dispositive power and voting power. Its address of the principal office is 125 West 55th Street, Level 22, New York, NY 10019.*
- *USRE held 3,517,612 of the shares, over all of which USRE has dispositive power and voting power. Its address of the principal office is One Queen Street East, Suite 2600, P.O. Box 101, Toronto, Ontario, Canada M5C 2W5.*
- *PIT held 1,758,806 of the shares, over all of which PIT has dispositive power and voting power. Its address of the principal office is c/o its Trustee 6860141 Canada Inc., British Columbia Investment Management Corporation, Sawmill Point, Suite 301-2940 Jutland Road, Victoria, British Columbia, Canada V8T 5K6.*
- *PIP2PX held 490,707 of the shares, over all of which PIP2PX has dispositive power and voting power. Its address of the principal office is 340 Terrace Building, 9515-107 Street, Edmonton, Alberta, Canada T5K 2C3.*
- *PIP2GV held 300,756 of the shares, over all of which PIP2GV has dispositive power and voting power. Its address of the principal office is 340 Terrace Building, 9515-107 Street, Edmonton, Alberta, Canada T5K 2C3.*

5 *Information presented is based on a Schedule 13G filed on February 6, 2007 by Franklin Resources, Inc., Charles B. Johnson, Rupert H. Johnson, Jr. and Franklin Advisers, Inc. This amount includes 11,092,300 shares of common stock beneficially owned by Franklin Advisers, Inc. or Fiduciary Trust Company International, subsidiaries of Franklin Resources, Inc. According to the Schedule 13G, Franklin Advisers, Inc. has sole voting and investment power over 11,091,300 of the shares and Fiduciary Trust Company International has sole voting and investment power over 1,000 of the shares. Each of the reporting persons disclaims beneficial ownership of the shares. The address of Franklin Resources, Inc. is One Franklin Parkway, San Mateo, California 94403.*

6 *Information presented is based on a Schedule 13G filed on February 14, 2008 by Tradewinds Global Investors, LLC. According to the Schedule 13G, Tradewinds Global Investors, LLC has sole voting authority over 5,248,053 of the shares and sole dispositive power over 8,392,505 of the shares. The address of Tradewinds Global Investors, LLC is 2049 Century Park East, 18th Floor, Los Angeles, California 90067.*

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).

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, 2007:

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	4,098,547[1,2,3,4]
Equity compensation plans not approved by security holders	260,000	22.51	--
Total	300,000	$ 22.51	4,098,547

The table does not include 96,305 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 554,277 shares remaining available for issuance under Puget Energy's Employee Stock Purchase Plan.*

2 *Includes 3,349,12 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, 499,423 shares at a target level or 776,603 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 2006 Long-Term Incentive Plan.*

4 *Includes 195,149 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 SERP. 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, 2007, 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-Plan 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 and February 28, 2008, in consideration of Mr. Reynolds' remaining Chief Executive Officer at least through May 6, 2008, 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.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

TRANSACTIONS WITH RELATED PERSONS

Our Board of Directors has adopted a written policy for the review and approval or ratification of related person transactions. Under the policy, our directors and executive officers are expected to disclose to our Chief Compliance Officer the material facts of any transaction that could be considered a related person transaction promptly upon gaining knowledge of the transaction. A related person transaction is generally defined as any transaction required to be disclosed under Item 404(a) of Regulation S-K, the SEC's related person transaction disclosure rule.

Any transaction reported to the Chief Compliance Officer will be reviewed according to the following procedures:

- If the Chief Compliance Officer determines that disclosure of the transaction is not required under the SEC's related person transaction disclosure rule, the transaction will be deemed approved and will be reported to the Audit Committee.
- If disclosure is required, the Chief Compliance Officer will submit the transaction to the Chair of the Audit Committee, who will review and, if authorized, will determine whether to approve or ratify the transaction. The Chair is authorized to approve or ratify any related person transaction involving an aggregate amount of less than $1.0 million or when it would be impracticable to wait for the next Audit Committee meeting to review the transaction.
- If the transaction is outside the Chair's authority, the Chair will submit the transaction to the Audit Committee for review and approval or ratification.

When determining whether to approve or ratify a related person transaction, the Chair of the Audit Committee or the Audit Committee, as applicable, will review relevant facts regarding the related person transaction, including:

- The extent of the related person's interest in the transaction;
- Whether the terms are comparable to those generally available in arms' length transactions; and
- Whether the related person transaction is consistent with the best interests of the Company.

If any related person transaction is not approved or ratified, the Committee may take such action as it may deem necessary or desirable in the best interests of the Company and its shareholders.

There were no related person transactions required to be disclosed pursuant to Item 404(a) of Regulation S-K in fiscal year 2007.

BOARD OF DIRECTORS AND CORPORATE GOVERNANCE

INDEPENDENCE OF THE BOARD

The Board has reviewed the relationships between Puget Energy (and its subsidiaries) and each of its directors and has determined that all of the directors, other than Stephen P. Reynolds, Puget Energy's Chairman, President and Chief Executive Officer (CEO), are independent under the NYSE corporate governance listing standards and Puget Energy's Corporate Governance Guidelines, which are available at Puget Energy's website, www.pugetenergy.com, by clicking on the section Corporate Governance. In making these determinations, the Board has established a categorical standard that a director's independence is not impaired solely as a result of the director, or a company for which the director or an immediate family member of the director serves as an executive officer, making payments to PSE for power or natural gas provided by PSE at rates fixed in conformity with law or governmental authority, unless such payments would automatically disqualify the director under the NYSE's corporate governance listing standards. The Board has also established a categorical standard that a director's independence is not impaired if a director is a director, employee or executive officer of another company that makes payments to or receives payments from Puget Energy, PSE, or any of their affiliates, for property or services in an amount which is less than the greater of $1.0 million or one percent of such other company's consolidated gross revenues, determined for the most recent fiscal year. These categorical standards will not apply, however, to the extent that Puget Energy would be required to disclose an arrangement as a related person transaction pursuant to Item 404 of Regulation S-K.

In making its independence determinations, the Board considered all relationships between its directors and Puget Energy (and its subsidiaries), including some that are not required to be disclosed in this report as related-person transactions. Messrs. Ayer, Cole, Moriguchi and Simon serve as directors or officers of, or otherwise have a financial interest in, entities that make payments to PSE for energy services provided to those entities at tariff rates established by the Washington Utilities and Transportation Commission. These transactions fall within the first categorical independence standard described above. In addition, PSE has entered into transactions with entities for whom Messrs. Cole, Frank and Simon serve as directors or officers, or in which they otherwise have a financial interest, that involve amounts that are less than the greater of $1.0 million or 1% of those entities' consolidated gross revenues. These transactions fall within the second categorical standard described above. PSE has also made a charitable contribution to an entity for which Ms. Narodick served as director. Because these relationships either fall within the Board's categorical independence standards or involve an amount that is not material to Puget Energy or the other entity, the Board has concluded that none of these relationships impair the independence of the applicable directors.

EXECUTIVE SESSIONS

Non-management directors meet in executive session on a regular basis, generally on the same date as each scheduled Board meeting. Because the Chairman of the Board is a member of management, the Lead Independent Director, Phyllis J. Campbell, who is not a member of management, presides over the executive sessions. Shareholders may communicate with the non-management directors of the Board through the procedures described in Item 10 of Part III of this annual report under the section "Communications with the Board."

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:

	2007		2006	
(DOLLARS IN THOUSANDS)	PUGET ENERGY	PSE	PUGET ENERGY	PSE
Audit fees[1]	$ 1,695	$ 1,680	$ 1,653	$ 1,530
Audit related fees[2]	108	108	100	100
Tax fees[3]	16	16	34	34
Total	$ 1,819	$ 1,804	$ 1,787	$ 1,664

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 Company's Forms 10-Q and consents and reviews of documents filed with the Securities and Exchange Commission. The 2007 fees are estimated and include an aggregate amount of $1.4 million and $1.4 million billed to Puget Energy and PSE, respectively, through December 2007. The 2006 fees include an aggregate amount of $1.1 million and $1.0 million billed to Puget Energy and PSE, respectively, through December 31, 2006.*

2 *Consists of employee benefit plan audits and due diligence reviews.*

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

The Audit Committee of the Company has adopted policies for the pre-approval of all audit and non-audit services provided by the Company's independent registered public accounting firm. The policies are designed to ensure that the provision of these services does not impair the firm's independence. Under the policies, unless a type of service to be provided by the independent registered public accounting firm 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 2007 and 2006, 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 65.

2) *Financial Statement Schedules*. Financial Statement Schedules of the Company located on page 131, as required for the years ended December 31, 2007, 2006 and 2005, consist of the following:

   I. Condensed Financial Information of Puget

   II. Valuation of Qualifying Accounts

3) Exhibits - see index on page 173.

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, INC.**
/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 29, 2008	Date: February 29, 2008

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

SIGNATURE	TITLE	DATE
	(Puget Energy and PSE unless otherwise noted)	
/s/ Stephen P. Reynolds (Stephen P. Reynolds)	Chairman, President and Chief Executive Officer	February 29, 2008
/s/ Eric M. Markell (Eric M. Markell)	Executive Vice President and Chief Financial Officer	
/s/ James W. Eldredge (James W. Eldredge)	Vice President, Controller and Chief Accounting Officer	
/s/ William S. Ayer (William S. Ayer)	Director	
/s/ Phyllis J. Campbell (Phyllis J. Campbell)	Director	
/s/ Craig W. Cole (Craig W. Cole)	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
/s/ Herbert B. Simon (Herbert B. Simon)	Director
/s/ George W. Watson (George W. Watson)	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.

	2.1	Agreement and Plan of Merger, dated October 25, 2007, by and among Puget Energy, Inc., Padua Holdings LLC, Padua Intermediate Holdings Inc. and Padua Merger Sub Inc. (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K, dated October 29, 2007, Commission File No. 1-16305).
*	3(i).1	Restated Articles of Incorporation of Puget Energy, as amended on May 8, 2007 and May 10, 2007.
	3(i).2	Restated Articles of Incorporation of PSE (incorporated herein by reference to 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 May 4, 2007 (incorporated herein by reference to Exhibit 3(ii).1 to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007, Commission File No. 1-16305 and 1-4393).
	3(ii).2	Amended and Restated Bylaws of PSE dated March 7, 2003 (incorporated herein by reference to Exhibit 3(ii).2 to the 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-fourth Supplemental Indentures defining the rights of the holders of PSE's Electric Utility First Mortgage Bonds (incorporated herein by reference to 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; Exhibit 2-m to Registration No. 2-37645; Exhibits 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 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 Report on Form 10-K for fiscal year ended December 31, 2004, Commission File No. 1-16305 and 1-4393; Exhibit 4.1 to Current Report on Form 8-K, dated May 23, 2005, Commission File No. 1-16305 and 1-4393; Exhibit 4.30 to 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 September 14, 2006, Commission File No. 1-4393 and Eighty-fifth Supplemental Indenture defining the rights of the holders of PSE's Electric Utility First Mortgage Bonds (filed herewith).
	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 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 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 Wells Fargo Bank, N.A., as Rights Agent (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Registration Statement on Form S-3, dated January 11, 2007, Commission File No. 1-16305).
	4.8	Amendment No. 1 dated October 25, 2007 to Rights Agreement between Puget Energy and Wells Fargo Bank, N.A., as Rights Agent (incorporated herein by reference to Exhibit 4.1 to Puget Energy's Current Report on Form 8-K, filed on October 29, 2007, Commission File No. 1-16305).
	4.9	First Supplemental Indenture dated as of October 1, 1959 (incorporated herein by reference to Exhibit 4-D to Registration No. 2-17876).

4.10	Sixth Supplemental Indenture dated as of August 1, 1966 (incorporated herein by reference to Exhibit to Form 8-K for month of August 1966, File No. 0-951).
4.11	Seventh Supplemental Indenture dated as of February 1, 1967 (incorporated herein by reference to Exhibit 4-M, Registration No. 2-27038).
4.12	Sixteenth Supplemental Indenture dated as of June 1, 1977 (incorporated herein by reference to Exhibit 6-05 to Registration No. 2-60352).
4.13	Seventeenth Supplemental Indenture dated as of August 9, 1978 (incorporated herein by reference to Exhibit 5-K.18 to Registration No. 2-64428).
4.14	Twenty-second Supplemental Indenture dated as of July 15, 1986 (incorporated herein by reference to Exhibit 4-B.20 to Form 10-K for the year ended September 30, 1986, File No. 0-951).
4.15	Twenty-seventh Supplemental Indenture dated as of September 1, 1990 (incorporated herein by reference to Exhibit 4-B.20, Form 10-K for the year ended September 30, 1998, File No. 10-951).
4.16	Twenty-eighth Supplemental Indenture dated as of July 31, 1991 (incorporated herein by reference to Exhibit 4-A, Form 10-Q for the quarter ended March 31, 1993, File No. 0-951).
4.17	Twenty-ninth Supplemental Indenture dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4-A to Registration No. 33-49599).
4.18	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).
4.19	Thirty-first Supplemental Indenture dated February 10, 1997 (incorporated herein by reference to Exhibit 4.30 to the Report on Form 10-K for the fiscal year ended December 31, 2002, Commission File No. 1-6305 and 1-4393).
4.20	Thirty-second Supplemental Indenture dated April 1, 2005, defining the rights of the holders of PSE's gas utility First Mortgage Bond (Exhibit 4.22 to the Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
4.21	Thirty-third Supplemental Indenture dated April 27, 2005, defining the rights of the holders of PSE's gas utility First Mortgage Bond (Exhibit 4.23 to the Report on Form 10-K for the fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
* 4.22	Thirty-fourth Supplemental Indenture dated April 28, 2006, defining the rights of the holders of PSE's gas utility First Mortgage Bond.
* 4.23	Thirty-fifth Supplemental Indenture dated April 27, 2007, defining the rights of the holders of PSE's gas utility First Mortgage Bond.
4.24	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).
4.25	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).
4.26	Unsecured Debt Indenture between Puget Sound Energy and The Bank of New York Trust Company, N.A. (as successor to 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, dated May 22, 2001, Commission File No. 1-4393).
4.27	Second Supplemental Indenture, dated as of June 1, 2007, between the Company and The Bank of New York Trust Company, N.A., as Trustee (incorporated herein by reference to Exhibit 4.1 to Puget Sound Energy's Current Report on Form 8-K, dated June 1, 2007, Commission File No. 1-4393).
4.28	Form of Replacement Capital Covenant (incorporate herein by reference to Exhibit 4.2 to Puget Sound Energy's Current Report on Form 8-K, dated June 1, 2007, Commission File No. 1-4393).
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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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) (incorporated herein by reference to Exhibit (10)-55 to 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) (incorporated herein by reference to Exhibit (10)-56 to 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) (incorporated herein by reference to Exhibit (10)-57 to 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 (incorporated herein by reference to Exhibit (10)-58 to 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 (incorporated herein by reference to Exhibit (10)-59 to 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) (incorporated herein by reference to Exhibit (10)-66 to 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) (incorporated herein by reference to Exhibit (10)-74 to 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 (incorporated herein by reference to Exhibit (10)-4 to 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 (incorporated herein by reference to Exhibit (10)-91 to 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 (incorporated herein by reference to Exhibit (10)-4 to 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 (incorporated herein by reference to Exhibit (10)-1 to 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 (incorporated herein by reference to Exhibit (10)-107 to 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 (incorporated herein by reference to Exhibit (10)-108 to 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) (incorporated herein by reference to Exhibit 10.115 to 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) (incorporated herein by reference to Exhibit 10.116 to 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 (incorporated herein by reference to 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 (incorporated herein by reference to Exhibit 10-P to Form 10-K for the year ended September 30, 1994, File No. 1-11271).

10.30 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. (incorporated herein by reference to Exhibit 10-1 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.31 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. (incorporated herein by reference to Exhibit 10-2 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.32 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. (incorporated herein by reference to Exhibit 10-3 to Form 10-Q for the quarter ended June 30, 2002, File No. 1-16305 and 1-4393).

10.33 Amended and Restated Credit Agreement dated March 29, 2007 among PSE and various banks named therein, Wachovia Bank National Association as administrative agent. (incorporated herein by reference to Exhibit 10.1 to Current Report on Form 8-K, dated April 3, 2007, Commission File No. 1-16305 and 1-4393).

10.34 Credit Agreement dated March 29, 2007, among PSE and various banks named therein, JP Morgan Chase Bank, N.A., as administrative agent, (incorporated herein by reference to Exhibit 10.2 to Current Report on Form 8-K, filed on April 3, 2007, Commission File No. 1-16305 and 1-4393).

10.35 Loan and Serving Agreement dated December 20, 2005, among PSE, PSE Funding, Inc., and J.P. Morgan Chase Bank as program agent (incorporated herein by reference to 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. (incorporated herein by reference to 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. (incorporated herein by reference to 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. (incorporated herein by reference to 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. (incorporated herein by reference to 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 (incorporated herein by reference to Exhibit 10.104 to the 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 (incorporated herein by reference to 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 (incorporated herein by reference to 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	Third Amendment dated February 28, 2008 to employment agreement with S.P. Reynolds, Chief Executive Officer and President, dated as of January 1, 2002 and amended as of February 9, 2006.
** 10.45	Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President, dated January 8, 2004 (incorporated herein by reference to Exhibit 10.90 to the 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 Unit Award Agreement with S. P. Reynolds, Chief Executive Officer and President dated, January 8, 2004 (incorporated herein by reference to Exhibit 10.91 to the Report on Form 10-K for the fiscal year ended December 31, 2003, Commission File No. 1-16305 and 1-4393).
** 10.47	Restricted Stock Award Agreement with S. P. Reynolds, Chief Executive Officer and President, dated January 8, 2002 (incorporated herein by reference to Exhibit 99.1 to Form S-8 Registration Statement, dated January 8, 2002, Commission File No. 333-76424).
** 10.48	Nonqualified Stock Option Grant Notice/Agreement with S. P. Reynolds, Chief Executive Officer and President dated March 11, 2002 (incorporated herein by reference to Exhibit 99.1 and Exhibit 99.2 to Form S-8 Registration Statement dated March 18, 2002, Commission File No. 333-84426).
** 10.49	Puget Sound Energy Amended and Restated Supplemental Executive Retirement Plan for Senior Management dated October 5, 2004. (incorporated herein by reference to Exhibit 10.55 to 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 Deferred Compensation Plan for Key Employees dated January 1, 2003. (incorporated herein by reference to Exhibit 10.56 to 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 Nonemployee Directors dated October 1, 2000. (incorporated herein by reference to Exhibit 10.57 to Report on Form 10-K for fiscal year ended December 31, 2005, Commission File No. 1-16305 and 1-4393).
** 10.52	Summary of Director Compensation (incorporated herein by reference to Exhibit 10.51 to Puget Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-16305 and 1-4393).
** 10.53	Performance-Based Restricted Stock Award Agreement with S.P. Reynolds, Chief Executive Officer and President, dated May 12, 2005 (incorporated herein by reference to Exhibit 10.4 to the Current Report on Form 8-K, dated May 12, 2005, Commission File Nos. 1-16305 and 1-4393).
** 10.54	Form of Amended and Restated Change of Control Agreement between Puget Sound Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K, dated February 14, 2006, Commission File Nos. 1-16305 and 1-4393).
** 10.55	Form of Performance-Based Restricted Stock Award Agreement between Puget Sound Energy and Key Employees (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K, dated February 28, 2006, Commission File No. 1-16305).
** 10.56	Summary of Severance Benefit for B.A. Valdman, Senior Vice President Finance and Chief Financial Officer (incorporated herein by reference to Exhibit 10.55 to Puget Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-16305 and 1-4393).
** 10.57	Restricted Stock Award Agreement with B.A. Valdman, Senior Vice President Finance and Chief Financial Officer, dated December 4, 2003 (incorporated herein by reference to Exhibit 10.56 to Puget Energy's Report on Form 10-K for the fiscal year ended December 31, 2006, Commission File No. 1-16305 and 1-4393).
10.58	Stock Purchase Agreement dated October 25, 2007 by and among Puget Energy, Inc. and the Purchasers named therein, (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K, dated October 29, 2007, Commission File No. 1-16305).
* 12.1	Statement setting forth computation of ratios of earnings to fixed charges of Puget Energy (2003 through 2007).
* 12.2	Statement setting forth computation of ratios of earnings to fixed charges of Puget Sound Energy (2003 through 2007).
* 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 – Eric M. Markell.
*	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 – Eric M. Markell.
*	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 – Eric M. Markell.

* *Filed herewith.*

** *Management contract or compensating plan or arrangement.*