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

FORM 10-Q

[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2005

OR

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

For the Transition period from ________ to _________

Commission File Number	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices, 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

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

Indicate by check mark whether Puget Energy, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes __X__ No _____

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

As of July 20, 2005, (i) the number of shares of Puget Energy, Inc. common stock outstanding was 100,291,193 ($.01 par value) and (ii) all of the outstanding shares of Puget Sound Energy, Inc. common stock were held by Puget Energy, Inc.

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DEFINITIONS

AFUDC	Allowance for Funds Used During Construction
APB	Accounting Principles Board
CAISO	California Independent System Operator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FPA	Federal Power Act
InfrastruX	InfrastruX Group, Inc.
kWh	Kilowatt Hour
LIBOR	London Interbank Offered Rate
MW	Megawatt (one MW equals one thousand kW)
MWh	Megawatt Hour (one MWh equals one thousand kWh)
PCA	Power Cost Adjustment
PCORC	Power Cost Only Rate Case
PGA	Purchased Gas Adjustment
PSE	Puget Sound Energy, Inc.
Puget Energy	Puget Energy, Inc.
SFAS	Statement of Financial Accounting Standards
Washington Commission	Washington Utilities and Transportation Commission

FILING FORMAT

This Quarterly Report on Form 10-Q is a combined quarterly report being filed separately by two different registrants, Puget Energy, Inc. (Puget Energy) and Puget Sound Energy, Inc. (PSE). Any references in this report to the “Company” are to Puget Energy and PSE collectively. PSE makes no representation as to the information contained in this report relating to Puget Energy and the subsidiaries of Puget Energy other than PSE and its subsidiaries.

FORWARD-LOOKING STATEMENTS

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

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

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

Risks relating to the regulated utility business (PSE)

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

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

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

Risks relating to both the regulated and non-regulated businesses

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

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

PART I FINANCIAL INFORMATION
Item 1. **Financial Statements**

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in thousands except per share amounts)
(Unaudited)

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2005	2004	2005	2004
Operating Revenues:				
Electric	$ 345,420	$ 303,091	$ 765,511	$ 695,587
Gas	162,567	119,479	483,695	395,170
Other	2,127	553	2,561	1,080
Total operating revenues	510,114	423,123	1,251,767	1,091,837
Operating Expenses:				
Energy costs:				
Purchased electricity	178,943	173,847	387,122	370,214
Electric generation fuel	12,894	21,014	33,342	35,002
Residential exchange	(37,105)	(35,362)	(92,151)	(89,785)
Purchased gas	98,142	63,703	299,887	226,109
Unrealized net gain on derivative instruments	(591)	(2,849)	(82)	(2,936)
Utility operations and maintenance	83,132	73,201	158,654	147,056
Other operations and maintenance	558	500	1,299	983
Depreciation and amortization	59,657	56,569	117,734	112,439
Conservation amortization	5,951	4,809	11,113	12,999
Taxes other than income taxes	50,521	42,550	120,221	106,774
Income taxes	6,093	(5,434)	52,175	33,665
Total operating expenses	458,195	392,548	1,089,314	952,520
Operating Income	51,919	30,575	162,453	139,317
Other income (deductions):				
Other income	1,598	1,570	2,762	1,638
Interest charges:				
AFUDC	2,041	1,079	3,503	2,157
Interest expense	(43,568)	(42,921)	(84,611)	(86,042)
Mandatorily redeemable securities interest expense	(23)	(23)	(45)	(45)
Income (loss) from continuing operations	11,967	(9,720)	84,062	57,025
Income from discontinued operations, net of tax	1,928	2,940	909	2,560
Net income (loss)	$ 13,895	$ (6,780)	$ 84,971	$ 59,585
Common shares outstanding weighted average (in thousands)	100,157	99,371	100,058	99,271
Diluted common shares outstanding weighted average (in thousands)	100,690	99,371	100,590	99,786
Basic earnings per common share from continuing operations	$ 0.12	$ (0.10)	$ 0.84	$ 0.57
Basic earnings per common share from discontinued operations	0.02	0.03	0.01	0.03
Basic earnings per common share	$ 0.14	$ (0.07)	$ 0.85	$ 0.60
Diluted earnings per common share from continuing operations	$ 0.12	$ (0.10)	$ 0.83	$ 0.57
Diluted earnings per common share from discontinued operations	0.02	0.03	0.01	0.03
Diluted earnings per common share	$ 0.14	$ (0.07)	$ 0.84	$ 0.60

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

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2005	2004	2005	2004
Net income (loss)	$ 13,895	$ (6,780)	$ 84,971	$ 59,585
Other comprehensive income, net of tax at 35%:				
Foreign currency translation adjustment	(15)	(25)	(12)	240
Unrealized gains (losses) on derivative instruments during the period	(8,281)	4,255	10,589	11,560
Reversal of unrealized gains (losses) on derivative instruments settled during the period	6,139	(1,511)	1,110	(4,081)
Loss from settlement of cash flow hedge contracts	(22,960)	--	(22,960)	--
Amortization of cash flow hedge contracts to earnings	72	--	72	--
Deferral of cash flow hedges related to the power cost adjustment mechanism	13,539	2,002	7,976	(2,686)
Other comprehensive income (loss)	(11,506)	4,721	(3,225)	5,033
Comprehensive income (loss)	$ 2,389	$ (2,059)	$ 81,746	$ 64,618

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

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

ASSETS

	JUNE 30, 2005	DECEMBER 31, 2004
Utility Plant: (at original cost, including construction work in progress of $205,541 and $129,966, respectively)		
Electric	$ 4,495,814	$ 4,389,882
Gas	1,937,595	1,881,768
Common	416,119	409,677
Less: Accumulated depreciation and amortization	(2,522,339)	(2,452,969)
Net utility plant	4,327,189	4,228,358
Other property and investments	159,085	157,670
Current assets:		
Cash	16,616	12,955
Restricted cash	1,105	1,633
Accounts receivable, net of allowance for doubtful accounts	203,523	137,659
Unbilled revenue	73,295	140,391
Purchased gas adjustment receivable	32,563	19,088
Materials and supplies, at average cost	98,380	97,578
Unrealized gain on derivative instruments	37,171	14,791
Prepayments and other	18,037	6,858
Deferred income taxes	--	1,415
Current assets of discontinued operations	116,670	110,922
Total current assets	597,360	543,290
Other long-term assets:		
Regulatory asset for deferred income taxes	138,347	127,252
Regulatory asset for PURPA contract buyout costs	201,205	211,241
Unrealized gain on derivative instruments	29,600	21,315
Power cost adjustment mechanism	5,518	--
Other	389,856	401,795
Long-term assets of discontinued operations	164,990	160,298
Total other long-term assets	929,516	921,901
Total assets	$ 6,013,150	$ 5,851,219

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

PUGET ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

CAPITALIZATION AND LIABILITIES

	JUNE 30, 2005	DECEMBER 31, 2004
Capitalization:		
Common shareholders' investment:		
Common stock $0.01 par value, 250,000,000 shares authorized, 100,285,742 and 99,868,368 shares outstanding, respectively	$ 1,003	$ 999
Additional paid-in capital	1,630,524	1,621,756
Earnings reinvested in the business	48,842	13,853
Accumulated other comprehensive loss, net of tax at 35%	(17,557)	(14,332)
Total shareholders' equity	1,662,812	1,622,276
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	280,250
Long-term debt	2,073,360	2,069,360
Total redeemable securities and long-term debt	2,312,999	2,351,499
Total capitalization	3,975,811	3,973,775
Minority interest in discontinued operations	5,346	4,648
Current liabilities:		
Accounts payable	146,537	226,478
Short-term debt	159,623	--
Current maturities of long-term debt	77,000	31,000
Accrued expenses:		
Taxes	97,440	81,315
Salaries and wages	14,310	13,829
Interest	28,045	29,005
Unrealized loss on derivative instruments	13,948	26,581
Deferred income taxes	451	--
Tenaska disallowance reserve	--	3,156
Other	32,021	34,918
Current liabilities of discontinued operations	61,232	51,892
Total current liabilities	630,607	498,174
Long-term liabilities:		
Deferred income taxes	799,760	795,291
Long-term portion of unrealized loss on derivative instruments	83	385
Other deferred credits	419,319	395,236
Long-term liabilities of discontinued operations	182,224	183,710
Total long-term liabilities	1,401,386	1,374,622
Total capitalization and liabilities	$ 6,013,150	$ 5,851,219

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

PUGET ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(Unaudited)

	SIX MONTHS ENDED JUNE 30,	
	2005	2004
Operating activities:		
Net income	$ 84,971	$ 59,585
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	117,734	121,410
Deferred income taxes and tax credits, net	(3,301)	27,238
Net unrealized gain on derivative instruments	(82)	(2,936)
Cash collateral received from energy suppliers	2,950	5,020
Increase (decrease) in residential exchange program	4,377	(1,651)
Impairment on InfrastruX investment	5,110	--
Other	20,081	21,144
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	(1,172)	154,567
Materials and supplies	(804)	(13,918)
Prepayments and other	(15,795)	(5,331)
Purchased gas adjustment receivable	(13,474)	(21,731)
Accounts payable	(81,051)	(62,446)
Taxes payable	20,779	(13,507)
Tenaska disallowance reserve	(3,156)	13,642
Accrued expenses and other	(552)	5,833
Net cash provided by operating activities	136,615	286,919
Investing activities:		
Construction and capital expenditures - excluding equity AFUDC	(221,369)	(235,201)
Energy efficiency expenditures	(15,611)	(8,338)
Refundable cash received for customer construction projects	6,137	4,810
Restricted cash	527	695
Other	18,492	(4,696)
Net cash used by investing activities	(211,824)	(242,730)
Financing activities:		
Change in short-term debt, net	163,749	38,521
Dividends paid	(43,910)	(43,288)
Issuance of common stock	2,714	2,848
Issuance of bonds	250,000	136,000
Redemption of bonds and notes	(203,456)	(187,004)
Redemption of trust preferred stock	(42,500)	--
Settlement of cash flow hedge derivative on treasury rate lock	(35,323)	--
Issuance and redemption costs of bonds and other	(11,500)	(1,417)
Net cash provided (used) by financing activities	79,774	(54,340)
Net increase (decrease) in cash	4,565	(10,151)
Change in cash from discontinued operations	(904)	5,386
Cash at beginning of year	12,955	14,778
Cash at end of period	$ 16,616	$ 10,013
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 89,742	$ 88,763
Income taxes	32,682	16,651

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2005	2004	2005	2004
Operating revenues:				
Electric	$ 345,420	$ 303,091	$ 765,511	$ 695,587
Gas	162,567	119,479	483,695	395,170
Other	2,127	553	2,561	1,080
Total operating revenues	510,114	423,123	1,251,767	1,091,837
Operating expenses:				
Energy costs:				
Purchased electricity	178,943	173,847	387,122	370,214
Electric generation fuel	12,894	21,014	33,342	35,002
Residential exchange	(37,105)	(35,362)	(92,151)	(89,785)
Purchased gas	98,142	63,703	299,887	226,109
Unrealized net gain on derivative instruments	(591)	(2,849)	(82)	(2,936)
Utility operations and maintenance	83,132	73,201	158,654	147,056
Other operations and maintenance	241	273	500	572
Depreciation and amortization	59,657	56,569	117,734	112,439
Conservation amortization	5,951	4,809	11,113	12,999
Taxes other than income taxes	50,521	42,550	120,221	106,774
Income taxes	6,285	(5,336)	52,830	33,844
Total operating expenses	458,070	392,419	1,089,170	952,288
Operating income	52,044	30,704	162,597	139,549
Other income (deductions):				
Other income, net of tax	1,598	1,570	2,762	1,638
Interest charges:				
AFUDC	2,041	1,079	3,503	2,157
Interest expense	(43,494)	(42,870)	(84,469)	(85,940)
Mandatorily redeemable securities interest expense	(23)	(23)	(45)	(45)
Net income (loss)	$ 12,166	$ (9,540)	$ 84,348	$ 57,359

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(Unaudited)

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2005	2004	2005	2004
Net income (loss)	$ 12,166	$ (9,540)	$ 84,348	$ 57,359
Other comprehensive income, net of tax at 35%:				
Unrealized gains (losses) on derivative instruments during the period	(8,281)	4,255	10,589	11,560
Reversal of unrealized gains (losses) on derivative instruments settled during the period	6,139	(1,511)	1,110	(4,081)
Loss from settlement of cash flow hedge contracts	(22,960)	--	(22,960)	--
Amortization of cash flow hedge contracts to earnings	72	--	72	--
Deferral of cash flow hedges related to the power cost adjustment mechanism	13,539	2,002	7,976	(2,686)
Other comprehensive income (loss)	(11,491)	4,746	(3,213)	4,793
Comprehensive income (loss)	$ 675	$ (4,794)	$ 81,135	$ 62,152

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

ASSETS

	JUNE 30, 2005	DECEMBER 31, 2004
Utility plant: (at original cost, including construction work in progress of $205,541 and $129,966, respectively)		
Electric	$ 4,495,814	$ 4,389,882
Gas	1,937,595	1,881,768
Common	416,119	409,677
Less: Accumulated depreciation and amortization	(2,522,339)	(2,452,969)
Net utility plant	4,327,189	4,228,358
Other property and investments	159,085	157,670
Current assets:		
Cash	16,616	12,955
Restricted cash	1,105	1,633
Accounts receivable, net of allowance for doubtful accounts	204,168	138,792
Unbilled revenue	73,295	140,391
Purchased gas adjustment receivable	32,563	19,088
Materials and supplies, at average cost	98,380	97,578
Unrealized gain on derivative instruments	37,171	14,791
Prepayments and other	17,423	6,247
Deferred income taxes	--	1,415
Total current assets	480,721	432,890
Other long-term assets:		
Regulatory asset for deferred income taxes	138,347	127,252
Regulatory asset for PURPA contract buyout costs	201,205	211,241
Unrealized gain on derivative instruments	29,600	21,315
Power cost adjustment mechanism	5,518	--
Other	389,246	401,030
Total other long-term assets	763,916	760,838
Total assets	$ 5,730,911	$ 5,579,756

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(Unaudited)

CAPITALIZATION AND LIABILITIES

	JUNE 30, 2005	DECEMBER 31, 2004
Capitalization:		
Common shareholder's investment:		
Common stock ($10 stated value) - 150,000,000 shares authorized, 85,903,791 shares outstanding	$ 859,038	$ 859,038
Additional paid-in capital	611,892	609,467
Earnings reinvested in the business	177,987	138,678
Accumulated other comprehensive loss, net of tax at 35%	(17,963)	(14,750)
Total shareholder's equity	1,630,954	1,592,433
Redeemable securities and long-term debt:		
Preferred stock subject to mandatory redemption	1,889	1,889
Junior subordinated debentures of the corporation payable to a subsidiary trust holding mandatorily redeemable preferred securities	237,750	280,250
Long-term debt	2,068,360	2,064,360
Total redeemable securities and long-term debt	2,307,999	2,346,499
Total capitalization	3,938,953	3,938,932
Current liabilities:		
Accounts payable	149,806	229,747
Short-term debt	159,623	--
Current maturities of long-term debt	77,000	31,000
Accrued expenses:		
Taxes	98,904	81,634
Salaries and wages	14,310	13,829
Interest	28,045	29,005
Unrealized loss on derivative instruments	13,948	26,581
Deferred income taxes	451	--
Tenaska disallowance reserve	--	3,156
Other	30,586	34,918
Total current liabilities	572,673	449,870
Long-term liabilities:		
Deferred income taxes	799,973	795,392
Unrealized loss on derivative instruments	83	385
Other deferred credits	419,229	395,177
Total long-term liabilities	1,219,285	1,190,954
Total capitalization and liabilities	$ 5,730,911	$ 5,579,756

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

PUGET SOUND ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(Unaudited)

	SIX MONTHS ENDED JUNE 30,	
	2005	2004
Operating activities:		
Net income	$ 84,348	$ 57,359
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	117,734	112,439
Deferred income taxes and tax credits, net	(2,877)	27,426
Net unrealized gain on derivative instruments	(82)	(2,936)
Cash collateral received from energy suppliers	2,950	5,020
Increase (decrease) in residential exchange program	4,377	(1,651)
Other	13,951	21,957
Change in certain current assets and liabilities:		
Accounts receivable and unbilled revenue	1,721	169,604
Materials and supplies	(803)	(13,190)
Prepayments and other	(11,177)	(67)
Purchased gas adjustment receivable	(13,474)	(21,731)
Accounts payable	(79,941)	(61,895)
Taxes payable	17,269	(17,212)
Tenaska disallowance reserve	(3,156)	13,642
Accrued expenses and other	(4,811)	3,724
Net cash provided by operating activities	126,029	292,489
Investing activities:		
Construction expenditures - excluding equity AFUDC	(212,054)	(224,579)
Energy efficiency expenditures	(15,611)	(8,338)
Restricted cash	527	695
Refundable cash received for customer construction projects	6,137	4,810
Other	18,507	(4,871)
Net cash used by investing activities	(202,494)	(232,283)
Financing activities:		
Change in short-term debt, net	159,623	28,100
Dividends paid	(45,039)	(44,114)
Issuance of bonds	250,000	--
Settlement of cash flow hedge derivative on treasury rate lock	(35,323)	--
Redemption of trust preferred stock	(42,500)	--
Redemption of bonds and notes	(200,000)	(50,197)
Issuance and redemption cost of bonds and other	(6,635)	1,240
Net cash provided (used) by financing activities	80,126	(64,971)
Net increase (decrease) in cash	3,661	(4,765)
Cash at beginning of year	12,955	14,778
Cash at end of period	$ 16,616	$ 10,013
Supplemental cash flow information:		
Cash payments for:		
Interest (net of capitalized interest)	$ 85,581	$ 87,249
Income taxes	32,682	16,651

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Consolidation Policy

BASIS OF PRESENTATION

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

The consolidated financial statements of Puget Energy include the accounts of Puget Energy and its subsidiaries, PSE and InfrastruX. Puget Energy holds all the common shares of PSE and holds a 90.9% interest in InfrastruX. The results of PSE and InfrastruX are presented on a consolidated basis. The financial position and results of operations for InfrastruX have been presented as a discontinued operation (see Note 2). PSE's consolidated financial statements include the accounts of PSE and its subsidiaries. Puget Energy and PSE are collectively referred to herein as "the Company." The consolidated financial statements are presented after elimination of all significant intercompany items and transactions. Certain amounts previously reported have been reclassified to conform with current year presentations with no effect on total equity or net income.

The consolidated financial statements contained in this Form 10-Q are unaudited. In the respective opinions of the management of Puget Energy and PSE, all adjustments necessary for a fair statement of the results for the interim periods have been reflected and were of a normal recurring nature. These condensed financial statements should be read in conjunction with the audited financial statements (and the Combined Notes thereto) included in the combined Puget Energy and PSE annual report on Form 10-K for the year ended December 31, 2004. Puget Energy previously had two reportable segments which included regulated utility operations (PSE) and utility construction services (InfrastruX). With the treatment of InfrastruX as a discontinued operation, Puget Energy now only has one reportable segment.

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.

(2) Discontinued Operations (Puget Energy Only)

Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy intends to monetize its interest in InfrastruX through a sale and to invest the proceeds of such monetization in its regulated utility subsidiary, PSE. This planned disposal meets the criteria established for recognition as a discontinued operation under Statement of Financial Accounting Standard (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Puget Energy has initiated discussions with interested parties who are in various stages of the due diligence process. The disposal is expected to be completed during 2005.

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

(DOLLARS IN THOUSANDS)	THREE MONTHS ENDED JUNE 30, 2005	THREE MONTHS ENDED JUNE 30, 2004	SIX MONTHS ENDED JUNE 30, 2005	SIX MONTHS ENDED JUNE 30, 2004
Revenues	$ 97,307	$ 92,816	$ 174,998	$ 167,571
Operating expenses (including interest expense)	(90,654)	(87,083)	(170,087)	(162,647)
Pre-tax income	6,653	5,733	4,911	4,924
Income tax expense	(4,028)	(2,504)	(3,302)	(2,118)
Minority interest in income of discontinued operations	(697)	(289)	(700)	(246)
Income from discontinued operations	$ 1,928	$ 2,940	$ 909	$ 2,560

Income from discontinued operations includes a charge of $1.1 million after-tax recorded in the first quarter 2005 related to estimated disposal of InfrastruX and a $5.1 million after-tax charge recorded in the second quarter 2005 to adjust Puget Energy's carrying value of InfrastruX to the estimated fair value. In accordance with SFAS No. 144, InfrastruX discontinued depreciation and amortization of its assets effective February 8, 2005. This discontinuation of depreciation and amoritization resulted in $4.7 million ($2.9 million after-tax) and $7.3 million ($4.5 million after-tax) lower depreciation and amortization expense than otherwise would have been recorded as continuing operations for the three and six months ended June 30, 2005, respectively.

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

(DOLLARS IN THOUSANDS)	JUNE 30, 2005	DECEMBER 31, 2004
Assets:		
Cash	$ 7,721	$ 6,817
Accounts receivable	81,051	78,646
Other current assets	27,898	25,459
Total current assets	116,670	110,922
Goodwill	43,886	43,503
Intangibles	15,693	16,680
Non-utility property and other	105,411	100,115
Total long-term assets	164,990	160,298
Total assets	$ 281,660	$ 271,220
Liabilities:		
Accounts payable	$ 8,663	$ 9,773
Short-term debt	12,423	8,297
Current maturities of long-term debt	6,778	7,933
Other current liabilities	33,368	25,889
Total current liabilities	61,232	51,892
Deferred income taxes	23,335	25,828
Long-term debt	140,871	143,172
Other deferred credits	18,018	14,710
Total long-term liabilities	182,224	183,710
Total liabilities	$ 243,456	$ 235,602

(3) **Earnings per Common Share** (Puget Energy Only)

Puget Energy's basic earnings per common share have been computed based on weighted average common shares outstanding of 100,157,000 and 100,058,000 for the three and six months ended June 30, 2005, respectively, and 99,371,000 and 99,271,000 for the three and six months ended June 30, 2004, respectively.

Puget Energy's diluted earnings per common share have been computed based on weighted average common shares outstanding of 100,690,000 and 100,590,000 for the three and six months ended June 30, 2005, respectively, and 99,371,000 and 99,786,000 for the three and six months ended June 30, 2004, respectively. These shares include the dilutive effect of securities related to employee and director equity plans.

(4) Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value, except for the normal purchase normal sale exception. The Company enters into both physical and financial contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts, option contracts and swaps. The majority of physical delivered contracts qualify for the normal purchase normal sale exception. Those contracts that do not meet normal purchase normal sale exception or cash flow hedge criteria are marked-to-market to current earnings in the income statement, subject to deferral under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," for energy related derivatives due to the $40 million cap of the Power Cost Adjustment (PCA) mechanism. Contracts that settle either prior to reaching the projected or actual $40 million PCA mechanism cap or after June 30, 2006 have 100% of the mark-to-market adjustment recorded in the income statement. Contracts that settle after reaching the projected or actual $40 million PCA mechanism cap up until June 30, 2006 have 99% of the mark-to-market adjustment deferred to the balance sheet, with the remaining 1% recorded in the income statement.

The nature of serving regulated electric customers with its wholesale portfolio of owned and contracted resources exposes the Company and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. The Company's energy risk management function monitors and manages these risks using analytical models and tools. The Company's energy risk management staff develops hedging strategies for the Company's energy supply portfolio. The first priority is to obtain reliable supply for delivery to the Company's retail customers. The second priority is to protect against unwanted risk exposure. The third priority is to optimize excess capacity or flexibility within the energy portfolio. The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore, mark-to-market adjustments associated with wholesale market transactions result as the Company seeks to hedge portfolio risks and optimize unused capacity. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios.

The Company has entered into master netting agreements with counterparties when available to mitigate credit exposure to those counterparties. The Company believes that entering into such agreements reduces risk of settlement default with the ability to make only one net payment. In addition, the Company believes risk is mitigated with an improved position in potential counterparty bankruptcy situations due to a consistent netting approach. The Company is subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

During the three months ended June 30, 2005, the Company recorded an increase in earnings for the change in the market value of derivative instruments not meeting cash flow hedge criteria of approximately $0.6 million compared to an increase in earnings of approximately $2.8 million for the three months ended June 30, 2004. At June 30, 2005, the Company had a net unrealized gain recorded in other comprehensive income of $13.1 million after-tax related to energy and financial contracts which meet the criteria for designation as cash flow hedges under SFAS No. 133. In 2005, a portion of the total unrealized gain on cash flow hedge transactions in other comprehensive income and the marked-to-market gain in the income statement were deferred in accordance with SFAS No. 71 due to the Company exceeding the $40 million cap under the PCA mechanism. When these transactions are realized, they will be reflected in the PCA calculation.

During the six months ended June 30, 2005, the Company recorded an increase in earnings for the change in the market value of derivative instruments not meeting cash flow hedge criteria of approximately $0.1 million compared to an increase in earnings of approximately $2.9 million for the six months ended June 30, 2004.

In the second quarter 2005, the Company entered into two forward starting interest rate swap contracts to hedge exposure to rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting interest rate swap is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value upon settlement. Alternatively, if interest rates decrease related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in the bond value upon settlement. The forward starting interest rate swap contracts were designated under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. When the forward starting interest rate swap contracts are settled upon issuance of debt, any gain or loss will be amortized from other comprehensive income to interest expense over the life of the issued debt. At June 30, 2005, the Company recorded a liability associated with these two contracts in the amount of $11.7 million and an unrealized loss in the amount of $7.6 million, after-tax, which is included in other comprehensive income.

In the second quarter 2005, the Company settled its two treasury lock contracts that were entered into in August 2004. The purpose of the treasury lock contracts was to hedge exposure to interest rate volatility for a debt offering of $250 million that was completed in May 2005. Since treasury interest rates decreased related to the hedged debt from the date of issuance of the treasury lock instruments, PSE paid the counterparties $35.3 million for the change in bond value when the contracts were settled. In addition, the bonds issued associated with the treasury lock instruments had a correspondingly lower interest rate since treasury rates decreased from the date of issuance of the treasury lock instruments. The treasury lock contracts were designated and documented under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. In the second quarter 2005, the settlement loss on these instruments amounted to $23.0 million, after-tax, and was recorded as a loss in other comprehensive income. In accordance with SFAS No. 133, this loss will be amortized out of other comprehensive income to current earnings as an increase to interest expense over the life of the new debt issued at an annual rate of approximately $1.2 million before tax. The ending balance in other comprehensive income related to the treasury lock contracts at June 30, 2005 was a loss of $22.9 million after-tax and accumulated amortization.

(5) Asset Retirement Obligations

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset.

The Company identified various asset retirement obligations under SFAS No. 143 upon initial adoption, and in 2005 identified an additional asset retirement obligation related to unprotected bare steel gas pipe. The Company has an obligation (1) to dismantle two leased electric generation turbine units and deliver the turbines to the nearest railhead at the termination of the lease in 2009; (2) to remove certain structures as a result of re-negotiations with the Department of Natural Resources of a now expired lease; (3) to replace or line all cast iron pipes in its service territory by 2007 as a result of a 1992 Washington Commission order; (4) to restore ash holding ponds at a jointly-owned coal-fired electric generating facility in Montana; and (5) to replace all unprotected bare steel gas pipe in its service territory by 2015 as a result of a January 31, 2005 Washington Commission order.

The following table describes all changes to the Company's asset retirement obligation liability during the six months ended June 30:

(DOLLARS IN THOUSANDS) AT JUNE 30	2005	2004
Asset retirement obligation at beginning of year	$ 3,516	$ 3,421
Liability recognized in the period	2,202	--
Liability settled in the period	(273)	--
Accretion expense	94	49
Asset retirement obligation at June 30	$ 5,539	$ 3,470

(6) Stock Compensation (Puget Energy Only)

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

(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	THREE MONTHS ENDED JUNE 30, 2005	THREE MONTHS ENDED JUNE 30, 2004	SIX MONTHS ENDED JUNE 30, 2005	SIX MONTHS ENDED JUNE 30, 2004
Net income (loss), as reported	$ 13,895	$ (6,780)	$ 84,971	$ 59,585
Add: Total stock-based employee compensation expense included in net income, net of tax	1,069	810	1,805	1,461
Less: Total stock-based employee compensation expense per the fair value method of SFAS No. 123, net of tax	(989)	(878)	(1,899)	(1,440)
Pro forma net income (loss)	$ 13,975	$ (6,848)	$ 84,877	$ 59,606
Earnings per share:				
Basic per common share as reported	$ 0.14	$ (0.07)	$ 0.85	$ 0.60
Diluted per common share as reported	$ 0.14	$ (0.07)	$ 0.84	$ 0.60
Basic per common share pro forma	$ 0.14	$ (0.07)	$ 0.85	$ 0.60
Diluted per common share pro forma	$ 0.14	$ (0.07)	$ 0.84	$ 0.60

(7) Retirement Benefits

The following summarizes the net periodic benefit cost for the three months ended June 30:

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2005	PENSION BENEFITS 2004	OTHER BENEFITS 2005	OTHER BENEFITS 2004
Service cost	$ 2,789	$ 2,663	$ 41	$ 50
Interest cost	5,994	6,075	264	438
Expected return on plan assets	(9,451)	(9,753)	(220)	(222)
Amortization of prior service cost	756	790	78	77
Recognized net actuarial (gain) loss	886	282	(271)	--
Amortization of transition (asset) obligation	(41)	(277)	104	105
Net periodic benefit cost (income)	$ 933	$ (220)	$ (4)	$ 448

The following summarizes the net periodic benefit cost for the six months ended June 30:

(DOLLARS IN THOUSANDS)	PENSION BENEFITS 2005	PENSION BENEFITS 2004	OTHER BENEFITS 2005	OTHER BENEFITS 2004
Service cost	$ 5,830	$ 5,171	$ 97	$ 100
Interest cost	11,958	12,041	668	876
Expected return on plan assets	(18,964)	(19,553)	(439)	(444)
Amortization of prior service cost	1,512	1,595	155	154
Recognized net actuarial (gain) loss	1,629	564	(271)	--
Amortization of transition (asset) obligation	(82)	(552)	209	210
Net periodic benefit cost (income)	$ 1,883	$ (734)	$ 419	$ 896

The Company previously disclosed in its financial statements for the year ended December 31, 2004 that it expected contributions by the Company to fund the pension and other benefits plans for the year ended December 31, 2005 to be $2.0 million and $1.4 million, respectively. During the three and six months ended June 30, 2005, the actual cash contributions to the pension plans were $0.3 million and $0.9 million, respectively. In addition, some plan participants chose lump sum pension payments totaling $0.6 million and deferred them under the Company's deferred compensation plan in the first quarter 2005. Based on this activity, the Company anticipates contributing an additional $0.6 million to the Company's pension plan in 2005. The full amount of the pension plan funding for 2005 is for the Company's non-qualified supplemental retirement plan.

During the three and six months ended June 30, 2005, actual other post-retirement medical benefit plan contributions were $0.6 million and $1.0 million, respectively, and the Company expects to make additional contributions of $0.4 million for a total of $1.4 million in 2005.

On May 19, 2004, FASB issued FASB Staff Position No. 106-2 "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" as the result of the new Medicare Prescription Drug Improvement and Modernization Act which was signed into law in December 2003. The law provides a subsidy for plan sponsors that provide prescription drug benefits to Medicare beneficiaries that are equivalent to the Medicare Part D plan. Based on new Medicare regulations issued in May 2005, the Company determined that it provides benefits at a higher level than provided under Medicare Part D, and therefore would qualify for federal tax subsidies. As a result, the Company reduced its accumulated post retirement benefit obligation by $4.1 million in the second quarter 2005 and reduced its estimated accrued expense recorded for the six months ended June 2005 for the 2005 plan year by $0.4 million.

(8) Purchased Gas Adjustment Mechanism True-Up

In the second quarter 2005, PSE determined from a review of its Purchased Gas Adjustment (PGA) mechanism that a gas demand charge created during the settlement of the 2001 general rate case for a gas customer rate class had not been included within the parameters to calculate the costs under the PGA mechanism for rate recovery purposes. As a result, the balance of the PGA mechanism receivable has been overstated due to the exclusion of this charge for a 31-month period from September 1, 2002 to March 31, 2005. The PGA mechanism balance and gas costs at June 30, 2005 include a one-time true-up of $5.0 million to reflect the impact of the demand charge. The total impact to earnings, net of tax, was $3.3 million, reflected in the quarter ended June 30, 2005. The effect of the true-up was not material to any one quarter since September 1, 2002.

(9) Other

On June 7, 2005, PSE filed a power cost only rate case (PCORC) with the Washington Utilities and Transportation Commission (Washington Commission) to help recover the higher cost of power. The PCORC requested a 3.7% increase in electric rates, or $55.6 million annually. Included in the request is recovery of capital and anticipated operating costs for the newly acquired Hopkins Ridge wind project once it goes online, which is expected in late 2005. The PCORC process is an accelerated rate proceeding where only power costs and new resources are reviewed. The PCORC proceeding can take up to five months to be concluded.

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

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

In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46R, "Consolidation of Variable Interest Entities" (FIN 46R). FIN 46R requires that if a business entity has a controlling financial interest in a variable interest entity, the financial statements of the variable interest entity must be included in the consolidated financial statements of the business entity. The Company has evaluated its purchase power agreements and determined that three counterparties may be considered variable interest entities. Consistent with FIN 46R, PSE submitted requests for information to those parties; however, the parties have refused to submit to PSE the necessary information for PSE to determine whether they meet the requirements of a variable interest entity. PSE also determined that it does not have a contractual right to such information. PSE will continue to submit requests for information to the counterparties on a quarterly basis in accordance with FIN 46R.

For the three purchase power agreements that may be considered variable interest entities under FIN 46R, PSE is required to buy all the generation from these plants, subject to displacement by PSE, at rates set forth in the purchase power agreements. If at any time the counterparties cannot deliver energy to PSE, PSE would have to buy energy in the wholesale market at prices which could be higher or lower than the purchase power agreement prices. PSE's Purchased Electricity expense for the three months ended June 30, 2005 and 2004 for these three entities was $41.6 million and $31.1 million, respectively. PSE's Purchased Electricity expense for the six months ended June 30, 2005 and 2004 for these three entities was $113.5 million and $110.0 million, respectively.

On July 12, 2005, Puget Energy received a notice of proposed adjustment (NOPA) from the Internal Revenue Service relating to a deduction in Puget Energy's 2003 tax return. The deduction relates to the receivable balance due from the California Independent System Operator Corporation (CAISO). The NOPA states that the deduction is not valid for the 2003 tax year and requests payment of approximately $14.5 million in taxes and approximately $1.0 million in related interest. Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction, however the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings as it would be recognized as a deferred tax asset.

(10) New Accounting Pronouncements

In December 2004, FASB issued SFAS No. 123R, "Share-Based Payment", which revises SFAS No. 123, "Accounting For Stock-Based Compensation." SFAS No. 123R requires companies that issue share-based payment awards to employees for goods or services to recognize as compensation expense, the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS No. 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS No. 123R was originally effective for interim reporting periods beginning after June 15, 2005. However, on April 14, 2005, the Securities and Exchange Commission delayed implementation of SFAS No. 123R to annual reporting periods beginning after June 15, 2005. The Company is currently evaluating what impact the application of SFAS No. 123R will have on its operations. The Company had adopted the fair value provisions of SFAS No. 123 "Accounting for Stock Based Compensation" in January 2003.

In March 2005, FASB issued FIN 47, which finalized a proposed interpretation of SFAS No. 143 titled "Accounting for Conditional Asset Retirement Obligations." The interpretation addresses the issue of whether SFAS No. 143 requires an entity to recognize a liability for a legal obligation to perform asset retirement when the asset retirement activities are conditional on a future event, and if so, the timing and valuation of the recognition. The decision reached by FASB was that there are no instances where a law or regulation obligates an entity to perform retirement activities but then allows the entity to permanently avoid settling the obligation. The Company is currently evaluating what impact FIN 47 will have on potential asset retirement obligations. The adoption of FIN 47 is effective for fiscal years ending after December 15, 2005, and is required to be accounted for as a cumulative effect of an accounting change.

Item 2. **Management's Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion of the Company's financial condition and results of operations contains forward-looking statements that involve risks and uncertainties, such as statements of the Company's plans, objectives, expectations and intentions. Words such as "anticipates," "believes," "estimates," "expects," "future," "intends," "plans," "projects," "predicts," "will likely result," and "will continue" and similar expressions are used to identify 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. The Company's actual results could differ materially from those anticipated in these forward-looking statements for many reasons, including the factors described below and under the caption "Forward-Looking Statements" at the beginning of this report. You should not place undue reliance on these forward-looking statements, which apply only as of the date of this Form 10-Q.

Overview

Puget Energy is an energy services holding company and all of its operations are conducted through its two subsidiaries. These subsidiaries are PSE, a regulated electric and gas utility company, and InfrastruX, a utility construction and services company. Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy intends to monetize its interest in InfrastruX through a sale and to invest the proceeds of such monetization in its regulated utility subsidiary, PSE. See section titled "InfrastruX" for further discussion.

PUGET SOUND ENERGY

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

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

PSE's main operational objective is to provide reliable, safe and cost-effective energy to its customers. To help accomplish this objective, PSE is attempting to be more self-sufficient in energy generation resources. Owning more generation resources will reduce the Company's reliance on the wholesale market. PSE is continually exploring new electric-power resource generation and long-term purchase power agreements to meet this goal. The completion of its acquisition of the Hopkins Ridge wind project in the first quarter 2005 and the issued notice to proceed with construction of the project was one step in reaching this goal. The Hopkins Ridge wind project is expected to provide up to 150 MW of capacity or 52 average MW, and is expected to be completed by the end of 2005. In addition, PSE continues negotiations from its September 2004 non-binding letter of intent to acquire the Wild Horse wind project, which is anticipated to provide approximately 230 MW of capacity or 77 average MW.

The Hopkins Ridge wind project and proposed Wild Horse wind project are part of PSE's long-term electric Least Cost Plan that was filed May 2, 2005 with the Washington Commission. The plan supports a strategy of diverse resource acquisitions including resources fueled by natural gas and coal, renewable resources and shared resources. The Least Cost Plan will be followed by issuing an all-source request for proposal (RFP) in late 2005. On July 29, 2005, PSE filed a draft version of this all-source RFP with the Washington Commission.

Results of Operations

PUGET ENERGY

All the operations of Puget Energy are conducted through its subsidiaries, PSE and InfrastruX. Net income for the three months ended June 30, 2005 was $13.9 million on operating revenues of $510.1 million compared to a loss of $6.8 million on operating revenues of $423.1 million for the same period in 2004. The net income and loss for both periods includes the results of discontinued operations for InfrastruX.

Basic and diluted earnings per share for the three months ended June 30, 2005 were $0.14 compared to a basic and diluted loss per share for the three months ended June 30, 2004 of $0.07. Included in the basic and diluted earnings per share for the three months ended June 30, 2005 was $0.02 earnings per share related to discontinued operations and estimated loss on disposal of InfrastruX. Included in the basic and diluted loss per share for the three months ended June 30, 2004 was $0.03 earnings per share related to discontinued operations of InfrastruX.

Net income for the three months ended June 30, 2005 was positively impacted by increased electric and gas margins of $42.7 million and $4.0 million, respectively, compared to the same period in 2004 mainly due to the Tenaska disallowance in May 2004 and increased electric and gas usage compared to the same period in 2004 offset by a one-time true-up of previously reported purchased gas costs. Net income was negatively impacted by higher utility operations and maintenance expenses as a result of higher production and higher depreciation and amortization expense from the acquisition of Frederickson 1 in April 2004 and other PSE transmission and distribution system infrastructure projects.

For the six months ended June 30, 2005, Puget Energy's net income was $85.0 million on operating revenues of $1.3 billion compared to net income of $59.6 million on operating revenues of $1.1 billion for the same period in 2004. Basic and diluted earnings per share for the six months ended June 30, 2005 was $0.85 and $0.84, respectively, compared to basic and diluted earnings per share of $0.60 for the same period in 2004. Included in the basic and diluted earnings per share for the six months ended June 30, 2005 was $0.01 earnings per share related to discontinued operations of InfrastruX.

Net income for the six months ended June 30, 2005 was positively impacted by increased electric and gas margins of $50.1 million and $4.5 million, respectively, compared to the same period in 2004, mainly due to the Tenaska disallowance in May 2004 and increased electric and gas usage offset by a one-time true-up of previously reported purchased gas costs.

PUGET SOUND ENERGY

PSE's operating revenues and associated expenses are not generated evenly during the year. Variations in energy usage by consumers occur from season to season and from month to month within a season, primarily as a result of weather conditions. PSE normally experiences its highest retail energy sales during the heating season in the first and fourth quarters of the year. Varying wholesale electric prices and the amount of hydroelectric energy supplies available to PSE also make quarter-to-quarter comparisons difficult.

ENERGY MARGINS

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

The following table displays the details of electric margin changes for the three months ended June 30, 2005 compared to the same period in 2004. Electric margin is electric sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes, and the cost of generating and purchasing electric energy sold to customers, including transmission costs to bring electric energy to PSE's service territory.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED JUNE 30	ELECTRIC MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Electric retail sales revenue	$ 316.5	$ 280.9	$ 35.6	12.7 %
Electric transportation revenue	2.4	2.4	--	-- %
Other electric revenue-gas supply resale	1.0	0.6	0.4	66.7 %
Total electric revenue for margin	319.9	283.9	36.0	12.7 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(7.2)	(5.6)	(1.6)	(28.6)%
Pass-through revenue-sensitive taxes	(23.6)	(20.9)	(2.7)	(12.9)%
Residential exchange credit	37.1	35.4	1.7	4.8 %
Net electric revenue for margin	326.2	292.8	33.4	11.4 %
Minus power costs:				
Fuel	(12.9)	(21.0)	8.1	38.6 %
Purchased electricity, net of sales to other utilities and marketers	(152.4)	(132.0)	(20.4)	(15.5)%
Total electric power costs	(165.3)	(153.0)	(12.3)	(8.0)%
Electric margin before PCA	160.9	139.8	21.1	15.1 %
Tenaska disallowance reserve	--	(36.5)	36.5	*
Power cost deferred under the PCA mechanism	(9.6)	5.3	(14.9)	*
Electric margin[1]	$ 151.3	$ 108.6	$ 42.7	39.3 %

**Percent change not applicable or unmeaningful.*

[1] *Electric margin does not include any allocation for depreciation expense.*

The following table displays the details of electric margin changes for the six months ended June 30, 2005 compared to the same period in 2004.

(Dollars in Millions) Six Months Ended June 30	Electric Margin 2005	2004	Change	Percent Change
Electric retail sales revenue	$ 703.6	$ 648.4	$ 55.2	8.5 %
Electric transportation revenue	5.1	4.6	0.5	10.9 %
Other electric revenue-gas supply resale	5.1	4.0	1.1	27.5 %
Total electric revenue for margin	713.8	657.0	56.8	8.6 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(13.7)	(14.1)	0.4	2.8 %
Pass-through revenue-sensitive taxes	(52.2)	(47.0)	(5.2)	(11.1)%
Residential exchange credit	92.2	89.8	2.4	2.7 %
Net electric revenue for margin	740.1	685.7	54.4	7.9 %
Minus power costs:				
Fuel	(33.4)	(35.0)	1.6	4.6 %
Purchased electricity, net of sales to other utilities and marketers	(362.2)	(330.8)	(31.4)	(9.5)%
Total electric power costs	(395.6)	(365.8)	(29.8)	(8.1)%
Electric margin before PCA	344.5	319.9	24.6	7.7 %
Tenaska disallowance reserve	--	(36.5)	36.5	*
Tenaska reserve turnaround	5.3	--	5.3	*
Power cost deferred under the PCA mechanism	3.0	19.3	(16.3)	(84.5)%
Electric margin[1]	$ 352.8	$ 302.7	$ 50.1	16.6 %

* *Percent change not applicable or unmeaningful.*

[1] *Electric margin does not include any allocation for depreciation expense.*

Electric margin increased $42.7 million for the three months ended June 30, 2005 compared to the same period in 2004, primarily due to the Tenaska disallowance recorded in May 2004 and the disallowance set in rates, which reduced margin by $37.8 million for the three months ended June 30, 2004. In addition, electric margin increased as a result of the effects of the Power Cost Only Rate Case (PCORC) for the Frederickson 1 generating facility and other power costs that became effective May 24, 2004, and the effects of the electric general tariff increase effective March 4, 2005. The PCORC and the electric general rate case contributed $6.2 million to electric margin for the three months ended June 30, 2005 compared to the same period in 2004, offset by a $2.7 million Tenaska disallowance for the three months ended June 30, 2005. In addition, retail customer kWh sales (residential, commercial and industrial customers) increased 4.9% for the three months ended June 30, 2005 compared to 2004, which provided $6.9 million to electric margin, and changes in customer class usage (residential, commercial and industrial), increased margin by $8.2 million compared to the same period in 2004. These increases were partially offset by a reduction in customer deferral of excess power costs under the PCA mechanism, which decreased margin by $9.7 million for the three months ended June 2005 compared to the same period in 2004 due to overall lower power costs in 2005.

Electric margin increased $50.1 million for the six months ended June 30, 2005 compared to the same period in 2004 primarily as a result of the aforementioned Tenaska disallowance recorded in May 2004 and the disallowance set in rates, which reduced margin by $37.8 million for the six months ended June 30, 2004. Also contributing to the increase were the effects of the PCORC and the electric general tariff increases, which provided a combined $9.4 million to margin. In February 2005, a final resolution and recovery of $6.0 million return on the Tenaska Regulatory asset for the PCA 2 period was received which increased margin by the same amount. Other items that increased margin include a 2.4% increase in retail customer usage, which contributed $7.8 million to margin, and a change in customer class usage, which increased margin by $7.2 million. These increases were partially offset by a reduction in customer deferral of excess power costs under the PCA mechanism which decreased margin by $16.2 million for the six months ended June 2005 compared to the same period in 2004 due to overall lower power costs in 2005.

The following table displays the details of gas margin changes for the three months ended June 30, 2005 compared to the same period in 2004. Gas margin is gas sales to retail and transportation customers less pass-through tariff items and revenue-sensitive taxes and the cost of gas purchased, including gas transportation costs to bring gas to PSE's service territory.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED JUNE 30	GAS MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 155.2	$ 112.6	$ 42.6	37.8 %
Gas transportation revenue	3.2	3.1	0.1	3.2 %
Total gas revenue for margin	158.4	115.7	42.7	36.9 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(1.0)	(0.5)	(0.5)	(100.0)%
Pass-through revenue-sensitive taxes	(13.7)	(9.9)	(3.8)	(38.4)%
Net gas revenue for margin	143.7	105.3	38.4	36.5 %
Minus purchased gas costs[1]	(98.1)	(63.7)	(34.4)	(54.0)%
Gas margin[2]	$ 45.6	$ 41.6	$ 4.0	9.6 %

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

[2] Gas margin does not include any allocation for depreciation expense.

The following table displays the details of gas margin changes for the six months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) SIX MONTHS ENDED JUNE 30	GAS MARGIN 2005	2004	CHANGE	PERCENT CHANGE
Gas retail revenue	$ 468.1	$ 382.0	$ 86.1	22.5 %
Gas transportation revenue	6.6	6.5	0.1	1.5 %
Total gas revenue for margin	474.7	388.5	86.2	22.2 %
Adjustments for amounts included in revenue:				
Pass-through tariff items	(2.9)	(1.6)	(1.3)	(81.3)%
Pass-through revenue-sensitive taxes	(38.7)	(32.1)	(6.6)	(20.6)%
Net gas revenue for margin	433.1	354.8	78.3	22.1 %
Minus purchased gas costs[1]	(299.9)	(226.1)	(73.8)	(32.6)%
Gas margin[2]	$ 133.2	$ 128.7	$ 4.5	3.5 %

[1] See Footnote 1 for three months ended June 30 Gas Margin table.

[2] Gas margin does not include any allocation for depreciation expense.

Gas margin increased $4.0 million for the three months ended June 30, 2005 compared to the same period in 2004 primarily due to increased gas usage and the gas general tariff rate case. Gas margin increased $4.0 million as a result of the gas general tariff increase effective March 4, 2005. Retail customer therm sales increased 12.8% for the three months ended June 30, 2005 compared to the same period in 2004, which provided $5.3 million to gas margin. The increased usage was primarily due to overall cooler weather for the three months ended June 30, 2005 compared to the same period in 2004, with 15.2% more heating degree days for the three months ended June 30, 2005 compared to the same period in 2004. Negatively impacting gas margin for the three months ended June 30, 2005 was a $5.0 million one-time true-up of previously reported gas costs under the PGA mechanism. See further discussion under the section titled "Operating Expenses-Purchased Gas."

Gas margin increased $4.5 million for the six months ended June 30, 2005 compared to the same period in 2004. Gas margin increased $6.2 million as a result of the gas general tariff rate case. In addition, retail customer therm sales increased 1.4% for the six months ended June 30, 2005 compared to the same period in 2004, which provided $1.7 million to gas margin, and changes in customer class usage provided $2.1 million to gas margin. Negatively impacting gas margin for the six months ended June 30, 2005, was the $5.0 million one-time true-up of previously reported gas costs as noted above.

ELECTRIC OPERATING REVENUES

The table below sets forth changes in electric operating revenues for PSE for the three months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 152.9	$ 132.3	$ 20.6	15.6 %
Commercial sales	150.0	131.5	18.5	14.1 %
Industrial sales	23.2	20.8	2.4	11.5 %
Other retail sales, including unbilled revenue	(9.6)	(3.7)	(5.9)	(159.5)%
Total retail sales	316.5	280.9	35.6	12.7 %
Transportation sales	2.4	2.4	--	-- %
Sales to other utilities and marketers	16.9	10.7	6.2	57.9 %
Other	9.6	9.1	0.5	5.5 %
Total electric operating revenues	$ 345.4	$ 303.1	$ 42.3	14.0 %

Electric retail sales increased $35.6 million for the three months ended June 30, 2005 compared to the same period in 2004 due primarily to rate increases related to the PCORC and the electric general rate case, and increased retail customer usage. The PCORC and electric general rate case provided a combined additional $13.6 million to electric operating revenues for the three months ended June 30, 2005 compared to the same period in 2004. Retail electricity usage increased 215,174 MWh or 4.9% for the three months ended June 30, 2005 compared to the same period in 2004. The increase in electricity usage was primarily the result of cooler temperatures for the three months ended June 30, 2005 compared to the same period in 2004, and due to a 1.9% increase in the average number of customers served.

During the three month period ended June 30, 2005, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $38.8 million compared to $37.0 million for the same period in 2004. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers increased $6.2 million compared to the three month period ended June 30, 2004 primarily due to an increase of 165,470 MWh sold related to excess generation available for sale on the wholesale market. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions. Sales to other utilities and marketers is included in the PCA mechanism as a reduction in determining net power costs.

The table below sets forth changes in electric operating revenues for PSE for the six months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) SIX MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Electric operating revenues:				
Residential sales	$ 364.8	$ 336.7	$ 28.1	8.3 %
Commercial sales	307.9	285.2	22.7	8.0 %
Industrial sales	45.2	43.2	2.0	4.6 %
Other retail sales, including unbilled revenue	(14.4)	(16.6)	2.2	13.3 %
Total retail sales	703.5	648.5	55.0	8.5 %
Transportation sales	5.1	4.6	0.5	10.9 %
Sales to other utilities and marketers	33.2	22.2	11.0	49.5 %
Other	23.7	20.3	3.4	16.7 %
Total electric operating revenues	$ 765.5	$ 695.6	$ 69.9	10.0 %

Electric retail sales increased $55.0 million for the six months ended June 30, 2005 compared to the same period in 2004 due primarily to rate increases related to the PCORC and the electric general rate case, and increased retail customer usage. The PCORC and electric general rate case provided a combined additional $28.4 million to electric operating revenues for the six months ended June 30, 2005 compared to the same period in 2004. Retail electricity usage increased 243,506 MWh or 2.4% for the six months ended June 30, 2005 compared to the same period in 2004. The increase in electricity usage was mainly the result of a 1.9% higher average number of customers served in the six month period ended June 30, 2005 compared to the same period in 2004.

During the six month period ended June 30, 2005, the benefits of the Residential and Farm Energy Exchange Benefit credited to customers reduced electric operating revenues by $96.4 million compared to $94.0 million for the same period in 2004. This credit also reduced power costs by a corresponding amount with no impact on earnings.

Sales to other utilities and marketers increased $11.0 million compared to the six month period ended June 30, 2004 primarily due to an increase of 165,470 MWh sold related to excess generation available for sale on the wholesale market. The increase in MWh sold was due to differences in timing of the need for power to serve base load and actual weather conditions.

Other electric revenues increased $3.4 million for the six month period ended June 30, 2005 compared to the same period in 2004, primarily from the sale of excess non-core gas and electric transmission. Non-core gas sales are included in the PCA mechanism calculation as a reduction in determining net power costs.

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

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

GAS OPERATING REVENUES

The table below sets forth changes in gas operating revenues for PSE for the three months ended June 30, 2005 compared to the same period in 2004.

(Dollars in Millions) Three Months Ended June 30	2005	2004	Change	Percent Change
Gas operating revenues:				
Residential sales	$ 94.8	$ 67.5	$ 27.3	40.4 %
Commercial sales	50.4	37.7	12.7	33.7 %
Industrial sales	10.0	7.4	2.6	35.1 %
Total retail sales	155.2	112.6	42.6	37.8 %
Transportation sales	3.2	3.1	0.1	3.2 %
Other	4.2	3.8	0.4	10.5 %
Total gas operating revenues	$ 162.6	$ 119.5	$ 43.1	36.1 %

Gas retail sales increased $42.6 million for the three months ended June 30, 2005 compared to the same period in 2004 due to higher Purchased Gas Adjustment (PGA) mechanism rates in 2005, approval of a 3.5% general gas rate increase in the gas general rate case effective March 4, 2005, and higher retail customer gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2004 that increased rates 17.6% annually. The PGA mechanism passes through to customers increases or decreases in the gas supply portion of the natural gas service rates based upon changes in the price of natural gas purchased from producers and wholesale marketers or changes in gas pipeline transportation costs. PSE’s gas margin and net income are not affected by changes under the PGA mechanism. For the three months ended June 30, 2005, the effects of the PGA mechanism rate increases provided an increase of $21.6 million in gas operating revenues. In addition, the gas general rate case increased gas rates by 3.5%, which provided an additional $4.0 million in gas operating revenue for the three months ended June 30, 2005 compared to the same period in 2004. Cooler weather in the three months ended June

30, 2005 compared to the same period in 2004 and a 3.2% increase in the average number of customers increased customer usage by 16.1 million therms and provided the remaining increase in retail gas revenues.

The table below sets forth changes in gas operating revenues for PSE for the six months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) SIX MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Gas operating revenues:				
Residential sales	$ 303.4	$ 248.3	$ 55.1	22.2 %
Commercial sales	141.6	115.1	26.5	23.0 %
Industrial sales	23.0	18.6	4.4	23.7 %
Total retail sales	468.0	382.0	86.0	22.5 %
Transportation sales	6.6	6.5	0.1	1.5 %
Other	9.1	6.7	2.4	35.8 %
Total gas operating revenues	$ 483.7	$ 395.2	$ 88.5	22.4 %

Gas retail sales increased $86.0 million for the six months ended June 30, 2005 compared to the same period in 2004 due to higher Purchased Gas Adjustment (PGA) mechanism rates in 2005, approval of a 3.5% general gas rate increase in the gas general rate case and higher retail customer gas usage. The Washington Commission approved a PGA mechanism rate increase effective October 1, 2004 that provided $68.0 million in gas revenues for the six months ended June 30, 2005 compared to the same period in 2004. In addition, the gas general rate case increase provided an additional $6.2 million in gas operating revenues for the six months ended June 30, 2005 compared to the same period in 2004. The remaining increase in gas retail revenues was primarily due to a higher average number of customers, which increased 3.2% for the six months ended June 30, 2005 compared to the same period in 2004.

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

TYPE OF RATE ADJUSTMENT	EFFECTIVE DATE	PERCENTAGE INCREASE IN RATES	ANNUAL INCREASE IN REVENUES (DOLLARS IN MILLIONS)
PGA	October 1, 2004	17.6 %	$ 121.7
Gas General Rate Case	March 4, 2005	3.5 %	26.3

OPERATING EXPENSES

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the three months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) THREE MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Purchased electricity	$ 178.9	$ 173.8	$ 5.1	2.9 %
Electric generation fuel	12.9	21.0	(8.1)	(38.6)%
Residential exchange credit	(37.1)	(35.4)	1.7	4.8 %
Purchased gas	98.1	63.7	34.4	54.0 %
Unrealized gain on derivative instruments	(0.6)	(2.8)	(2.2)	(78.6)%
Utility operations and maintenance	83.1	73.2	9.9	13.5 %
Depreciation and amortization	59.7	56.6	3.1	5.5 %
Taxes other than income taxes	50.5	42.6	7.9	18.5 %
Income taxes	6.3	(5.3)	11.6	* %

* *Percent change not applicable or unmeaningful.*

The table below sets forth significant changes in operating expenses for PSE and its subsidiaries for the six months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) SIX MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Purchased electricity	$ 387.1	$ 370.2	$ 16.9	4.6 %
Electric generation fuel	33.3	35.0	(1.7)	(4.9)%
Residential exchange credit	(92.2)	(89.8)	2.4	2.7 %
Purchased gas	299.9	226.1	73.8	32.6 %
Unrealized gain on derivative instruments	(0.1)	(2.9)	(2.8)	(96.6) %
Utility operations and maintenance	158.7	147.1	11.6	7.9 %
Depreciation and amortization	117.7	112.4	5.3	4.7 %
Taxes other than income taxes	120.2	106.8	13.4	12.5 %
Income taxes	52.8	33.8	19.0	56.2 %

Purchased electricity expenses increased $5.1 million and $16.9 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. The increase for the three months ended June 30, 2005 was primarily the result of higher customer usage, which increased both the amount of power purchased as well as generated power at PSE-controlled facilities. Total purchased power for the three months ended June 30, 2005 increased 264,281 MWh, or an increase of 7.4% compared to the same period in 2004. The increase for the six months ended June 30, 2005 was the result of higher purchases and higher wholesale market prices. Total purchased power for the six months ended June 30, 2005 increased 453,918 MWh, or a 5.7% increase over the same period in 2004. These increases were partially offset by a February 23, 2005 Washington Commission order concerning PSE's compliance filing related to the PCA 2 period of July 1, 2003 through June 30, 2004. In its order, the Washington Commission determined that PSE was allowed to reflect additional power costs totaling $6.0 million during the PCA 2 period of July 1, 2003 through December 31, 2003. These costs were deferred under the PCA mechanism, which resulted in a reduction in purchased electricity expense for the three and six months ended June 30, 2005.

PSE's hydroelectric production and related power costs in 2005 and 2004 have continued to be negatively impacted by below-normal winter precipitation and reduced snow pack in the Pacific Northwest region. The June 17, 2005 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 2005 would be 86% of normal, which compares to 80% of normal observed runoff for the same period in 2004. PSE cannot determine if this trend of lower than normal runoff will continue in future years nor what impact such a trend may have on the amount of electricity that will need to be purchased.

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

Electric generation fuel expense decreased $8.1 million and $1.7 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. The decrease for the three months ended June 30, 2005 is primarily related to a $6.9 million charge recorded in June 2004 related to a binding arbitration settlement between Western Energy Company and PSE. Excluding this settlement, the net decrease was $1.2 million related to the overall lower cost of gas for combustion turbine units due to lower generation. The change for the six months ended June 30, 2005 excluding the $6.9 million Western Energy Company settlement in June 2004 was an increase in electric generation fuel of $5.2 million. This increase is primarily related to increased costs for higher generation at combustion turbine units.

Purchased gas expenses increased $34.4 million and $73.8 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004 primarily due to an increase in PGA rates as approved by the Washington Commission. The PGA mechanism allows PSE to recover expected gas costs, and defer, as a receivable or liability, any gas costs that exceed or fall short of this expected gas cost amount in PGA mechanism rates, including accrued interest. The PGA mechanism receivable balance at June 30, 2005 and December 31, 2004 was $32.6 million and $19.1 million, respectively. A receivable balance in the PGA mechanism reflects a current underrecovery of market gas cost through rates.

In the second quarter 2005, PSE determined from a review of its PGA mechanism that a gas demand charge created during the settlement of the 2001 general rate case for a gas customer rate class had not been included within the parameters to calculate the costs under the PGA mechanism for rate recovery purposes. As a result, the balance of the PGA mechanism receivable has been overstated due to the exclusion of this charge over a 31-month period from September 1, 2002 to March 31, 2005. The PGA mechanism balance and gas costs at June 30, 2005 include a one-time true-up of $5.0 million to reflect the impact of the demand charge. The total impact to earnings, net of tax, was $3.3 million for the three and six months ended June 30, 2005. This adjustment impacts the comparability of gas margin information and purchased gas expense for both the three and six months ended June 30, 2005 compared with the same periods in 2004.

Unrealized gain on derivative instruments decreased $2.2 million and $2.8 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. The primary reason for the decrease is the timing of when the Company will be at or over the $40 million cap for the PCA mechanism in 2005 versus 2004, which affects the timing and extent of mark-to-market activity that is recorded in the income statement rather than being deferred on the balance sheet.

Utility operations and maintenance expense increased $9.9 million and $11.6 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. Included in the increases for the three and six months ended June 30, 2005 is a $1.3 million and $3.2 million increase, respectively, related to low-income program costs that are passed-through in retail rates with no impact on earnings. As a result, the impact on net income from utility operations and maintenance for the three and six months ended June 30, 2005 was an increase of $8.6 million and $8.4 million, respectively. The increases for both periods were mainly due to a $3.6 million and $4.3 million increase in production operations and maintenance costs for the three and six months ended June 30, 2005, respectively, associated with the Frederickson 1 generating facility which went into service in May 2004, and planned maintenance costs at the Encogen generating facility. Also included in the increase for the three and six months ended June 30, 2005 is a $1.4 million loss reserve associated with an arbitration panel's ruling in favor of the Muckleshoot Indian Tribe relating to the operation of a fish hatchery on the White River - see further discussion under the section titled “Other.” The remaining increase for both the three and six months ended June 30, 2005 relates to increased overhead line maintenance expenses and gas operation and distribution expenses. These increases were partially offset by lower storm damage costs of $2.0 million and $7.1 million for the three and six months ended June 30, 2005, respectively, due to less severe weather and outages in 2005. 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.

Depreciation and amortization expense increased $3.1 million and $5.3 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004. The increase was due to the effects of new plant placed in service during 2004, including $80.8 million in costs for the Frederickson 1 generating facility in April 2004 and $32.8 million for the Everett Delta gas transmission line late in 2004. PSE anticipates depreciation expense will increase in future years as investments in new generating resources and energy delivery infrastructure are completed.

Taxes other than income taxes increased $7.9 million and $13.4 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004 due primarily to increases in revenue-based Washington State excise tax and municipal tax due to increased operating revenues. Revenue sensitive Washington State excise and municipal taxes have no impact on earnings.

Income taxes increased $11.6 million and $19.0 million for the three and six months ended June 30, 2005, respectively, compared to the same periods in 2004 as a result of higher taxable income and a higher effective federal income tax rate.

OTHER INCOME AND INTEREST CHARGES

The table below sets forth significant changes in other income and interest charges for PSE and its subsidiaries for the six months ended June 30, 2005 compared to the same period in 2004.

(DOLLARS IN MILLIONS) SIX MONTHS ENDED JUNE 30	2005	2004	CHANGE	PERCENT CHANGE
Other income (net of tax)	$ 2.8	$ 1.6	$ 1.2	75.0 %
Interest charges	81.0	83.8	(2.8)	(3.3)%

Other income increased $1.2 million (after-tax) for the six months ended June 30, 2005 compared to the same period in 2004 primarily due to increases in the surrender value of corporate-owned life insurance policies and a higher level of equity portion of allowance for funds used during construction.

Interest charges decreased $2.8 million for the six months ended June 30, 2005 compared to the same period in 2004 due to the redemption of $137.5 million of long-term debt with rates ranging from 6.45% to 7.80% in 2004. Also, in May 2005, PSE redeemed $42.5 million of PSE's 8.231% Capital Trust Preferred Securities (classified as Junior Subordinated Debentures of the Corporation Payable to a Subsidiary Trust Holding Mandatorily Redeemable Preferred Securities on the balance sheet). These redemptions and resulting decreases in interest expense were partially offset by the issuance of $250 million of long-term senior notes in June 2005.

InfrastruX

Following a strategic review of Puget Energy's unregulated subsidiary, InfrastruX, on February 8, 2005, Puget Energy's Board of Directors decided to exit the utility construction services sector. Puget Energy intends to monetize its interest in InfrastruX through a sale and to invest the proceeds of such monetization into its regulated utility subsidiary, PSE. This planned disposal meets the criteria established for recognition as a discontinued operation under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," and is accounted for as such in Puget Energy's consolidated financial statements. Puget Energy has initiated discussions with interested financial and strategic parties who are in various stages of the due diligence process. The disposal of InfrastruX is expected to be completed during 2005.

For the three and six months ended June 30, 2005, Puget Energy reported InfrastruX related income from discontinued operations (net of taxes and minority interest) of $1.9 million and $0.9 million, respectively, compared to income of $2.9 million and $2.6 million (net of taxes and minority interest) for the three and six months ended June 30, 2004, respectively. Included in the income for discontinued operations is a charge of $1.1 million after-tax recorded in the first quarter 2005 related to estimated disposal of InfrastruX and a $5.1 million after-tax charge recorded in the second quarter 2005 to adjust Puget Energy's carrying value of InfrastruX to the estimated fair value. In accordance with SFAS No. 144, Puget Energy discontinued depreciation and amortization of InfrastruX's assets effective February 8, 2005. Following is a summary of Puget Energy's income from discontinued operations for the three and six months ended June 30, 2005:

(DOLLARS IN MILLIONS)	THREE MONTHS ENDED JUNE 30, 2005	SIX MONTHS ENDED JUNE 30, 2005
Net income reported by InfrastruX	$ 4.1	$ 2.5
Estimated selling costs of InfrastruX, after-tax	--	(1.1)
InfrastruX depreciation/amortization not recorded by Puget Energy, after-tax	2.9	4.5
Puget Energy tax benefit from goodwill deduction	0.7	0.7
Puget Energy carrying value adjustment of InfrastruX, after-tax	(5.1)	(5.1)
Minority interest in income from discontinued operations and other	(0.7)	(0.6)
Income from discontinued operations	$ 1.9	$ 0.9

InfrastruX's operating revenue for the three and six months ended June 30, 2005 was $97.3 million and $175.0 million, respectively, compared to $92.8 million and $167.6 million, respectively, for the same periods in 2004. Operating income for the three and six months ended June 30, 2005 was $6.2 million and $6.6 million, respectively, compared to $4.6 million and

$5.6 million, respectively for the same periods in 2004. InfrastruX's debt totaled $160.1 million at June 30, 2005 compared to $159.4 million at December 31, 2004.

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

CAPITAL REQUIREMENTS

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Puget Energy. The following are Puget Energy's aggregate consolidated (including PSE) contractual and commercial commitments from continuing operations as of June 30, 2005:

Puget Energy		PAYMENTS DUE PER PERIOD			
CONTRACTUAL OBLIGATIONS (DOLLARS IN MILLIONS)	TOTAL	2005	2006-2007	2008-2009	2010 & THEREAFTER
Long-term debt including interest	$ 3,939.8	$ 102.4	$ 476.0	$ 568.0	$ 2,793.4
Short-term debt	159.6	159.6	--	--	--
Junior subordinated debentures payable to a subsidiary trust [1]	910.7	10.0	39.8	39.8	821.1
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	172.0	11.3	54.1	53.2	53.4
Non-cancelable operating leases	128.9	6.7	33.0	27.5	61.7
Fredonia combustion turbines lease [2]	62.9	2.2	8.6	8.3	43.8
Energy purchase obligations	6,676.3	630.4	1,759.2	1,225.5	3,061.2
Financial hedge obligations	307.4	161.2	141.4	4.8	--
Pension funding[3]	44.8	3.4	8.2	9.8	23.4
Total contractual cash obligations	$ 12,404.3	$ 1,087.2	$ 2,520.3	$ 1,936.9	$ 6,859.9

		AMOUNT OF COMMITMENT EXPIRATION PER PERIOD			
COMMERCIAL COMMITMENTS (DOLLARS IN MILLIONS)	TOTAL	2005	2006-2007	2008-2009	2010 & THEREAFTER
Guarantees [4]	$ 131.0	$ --	$ 131.0	$ --	$ --
Liquidity facilities - available [5]	489.9	150.0	--	--	339.9
Lines of credit - available [6]	--	--	--	--	--
Energy operations letter of credit	0.5	--	0.5	--	--
Total commercial commitments	$ 621.4	$ 150.0	$ 131.5	$ --	$ 339.9

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

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

3 *Pension funding is based on an actuarial estimate.*

4 *In May 2004, InfrastruX signed a three-year credit agreement with a group of banks to provide up to $150 million in financing. Under the credit agreement, Puget Energy is the guarantor of the line of credit. Certain InfrastruX subsidiaries also have certain borrowing capacities for working capital purposes of which Puget Energy is not a guarantor. Of the $150 million available to InfrastruX, $131.0 was outstanding at June 30, 2005.*

5 *At June 30, 2005, PSE had available a $500 million unsecured credit agreement expiring in April 2010 and a $150 million receivables securitization facility that expires in December 2005. At June 30, 2005, PSE had no amounts sold under its receivables securitization facility. See "Accounts Receivable Securitization Program" under "Off-Balance Sheet Arrangements" below for further discussion. The credit agreement and securitization facility provide credit support for outstanding commercial paper of $159.6 million and a letter of credit totaling $0.5 million, thereby effectively reducing the available borrowing capacity under these liquidity facilities to $489.9 million.*

6 *Puget Energy has a $5 million line of credit with a bank. At June 30, 2005, $5.0 million was outstanding, leaving no amounts available to borrow under the agreement.*

Puget Sound Energy. The following are PSE's aggregate contractual and commercial commitments as of June 30, 2005:

Puget Sound Energy Contractual Obligations (Dollars in Millions)	Total	Payments Due Per Period 2005	2006-2007	2008-2009	2010 & Thereafter
Long-term debt including interest	$ 3,934.6	$ 102.3	$ 470.9	$ 568.0	$ 2,793.4
Short-term debt	159.6	159.6	--	--	--
Junior subordinated debentures payable to a subsidiary trust [1]	910.7	10.0	39.8	39.8	821.1
Mandatorily redeemable preferred stock	1.9	--	--	--	1.9
Service contract obligations	172.0	11.3	54.1	53.2	53.4
Non-cancelable operating leases	128.9	6.7	33.0	27.5	61.7
Fredonia combustion turbines lease [2]	62.9	2.2	8.6	8.3	43.8
Energy purchase obligations	6,676.3	630.4	1,759.2	1,225.5	3,061.2
Financial hedge obligations	307.4	161.2	141.4	4.8	--
Pension funding[3]	44.8	3.4	8.2	9.8	23.4
Total contractual cash obligations	$ 12,399.1	$ 1,087.1	$ 2,515.2	$ 1,936.9	$ 6,859.9

Commercial Commitments (Dollars in Millions)	Total	Amount of Commitment Expiration Per Period 2005	2006-2007	2008-2009	2010 & Thereafter
Liquidity facilities - available [4]	$ 489.9	$ 150.0	$ --	$ --	$ 339.9
Energy operations letter of credit	0.5	--	0.5	--	--
Total commercial commitments	$ 490.4	$ 150.0	$ 0.5	$ --	$ 339.9

1 *See note 1 above.*
2 *See note 2 above.*
3 *See note 3 above.*
4 *See note 5 above.*

Off-Balance Sheet Arrangements

Accounts Receivable Securitization Program

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

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

The receivables securitization facility expires in December 2005, but is terminable by PSE and Rainier Receivables upon notice to the receivables purchasers. At June 30, 2005, Rainier Receivables had no amounts sold under the receivables securitization facility, leaving a maximum amount of receivables available to be sold under the program of $150.0 million. During the three months ended June 30, 2005 and 2004, Rainier Receivables sold a cumulative $60.0 million and $145.0 million of receivables, respectively. During the six months ended June 30, 2005, and 2004, Rainier Receivables sold a cumulative $60.0 million and $267.0 million of receivables, respectively.

Fredonia 3 and 4 Operating Lease

PSE leases two combustion turbines for its Fredonia 3 and 4 electric generating facility pursuant to a master operating lease that was amended 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 June 30, 2005, PSE's outstanding balance under the lease was $55.4 million. The expected residual value under the lease is the lesser of $37.4 million or 60% of the cost of the equipment. In the event the equipment is sold to a third party upon termination of the lease and the aggregate sales proceeds are less than the unamortized value of the equipment, PSE would be required to pay the lessor contingent rent in an amount equal to the deficiency up to a maximum of 87% of the unamortized value of the equipment.

Utility Construction Program

Utility construction expenditures for generation, transmission and distribution are designed to meet continuing customer growth and to improve efficiencies of PSE's energy delivery systems. Construction expenditures, excluding equity Allowance for Funds Used During Construction (AFUDC) and customer refundable contributions, were $237.0 million for the six months ended June 30, 2005. Utility construction expenditures in 2005, 2006 and 2007 are anticipated to be approximately $580 million, $400 million and $384 million, respectively, including the new Hopkins Ridge wind project, but excluding amounts for new generation resources currently under evaluation. New generation resources under evaluation consist of the Wild Horse wind project, which if completed, is anticipated to have a total cost of approximately $350 million. The proposed utility construction expenditures and new generation resource expenditures, if acquired, are anticipated to be funded with a combination of short-term debt, long-term debt and equity. Construction expenditure estimates, including the new generation resources, are subject to periodic review and adjustment in light of changing economic, regulatory, environmental and efficiency factors.

New Generation Resources

On March 11, 2005, PSE completed the acquisition of the Hopkins Ridge wind project from Blue Sky Wind, LLC and issued its key contractor, RES America Construction, Inc., a notice to proceed with construction of the project. Hopkins Ridge is situated on 11,000 acres of remote, open wheat fields in southeastern Washington State. The Hopkins Ridge wind project will feature 83 Vestas 1.8-MW wind turbines providing up to 150 MW of capacity, or 52 average MW. Upon completion of construction, the energy will be delivered to PSE's service territory by BPA's transmission system via an interconnection. PSE anticipates spending approximately $200 million on the project, which it solely owns. Included in the $200 million estimate is $180 million to acquire and construct the wind plant, $10 million to fund upgrades to the transmission systems of the Bonneville Power Administration and other regional transmission providers, and the balance for development, transaction and financing costs.

In September 2004, PSE signed a non-binding letter of intent to obtain a 100% ownership interest in the proposed Wild Horse wind project. The project is located in central Washington State. The Wild Horse project is expected to have as many as 130 wind turbines which are anticipated to provide approximately 230 MW of capacity, or 77 average MW. The final agreement to purchase the Wild Horse wind project is anticipated to be executed in 2005.

Capital Resources

Cash From Operations

Cash generated from operations for the six months ended June 30, 2005 was $136.6 million. During that period, $47.4 million in cash was used for AFUDC and payment of dividends. Consequently, cash flows available for utility construction expenditures and other capital expenditures were $89.2 million or 39% of the $227.3 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the six months ended June 30, 2005. For the six months ended June 30, 2004, cash generated from operations was $286.9 million, $45.4 million of which was used for AFUDC and payment of dividends. Therefore, cash flows available for utility construction expenditures and other capital expenditures were $241.5 million, or 102% of the $236.6 million in construction expenditures (net of AFUDC and customer refundable contributions) and other capital expenditure requirements for the six month period ended June 30, 2004.

The overall cash generated from operating activities for the six month period ended June 30, 2005 decreased $150.3 million compared to the same period in 2004. The decrease was primarily the result of changes in the utilization of sales of accounts receivables to Rainier Receivables under the accounts receivable securitization program which contributed $179.0 million to the decrease in cash generated from operations. Also contributing to the decrease was a decrease in the amounts outstanding in accounts payable of $18.6 million, changes in the residential exchange program which contributed $6.0 million to the decrease, and a decrease in the previously accrued Tenaska disallowance of $16.8 million. These decreases were partially offset by an increase in net income of $25.4 million, an increase in cash flows from accounts receivables of $23.2 million and an increase in cash flow from the purchased gas receivable of $8.3 million.

FINANCING PROGRAM

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

RESTRICTIVE COVENANTS

In determining the type and amount of future financing, PSE may be limited by restrictions contained in its electric and gas mortgage indentures, articles of incorporation and certain loan agreements. Under the most restrictive tests, at June 30, 2005, PSE could issue:

- approximately $400 million of additional first mortgage bonds under PSE's electric mortgage indenture based on approximately $667 million of electric bondable property available for issuance, subject to an interest coverage ratio limitation of 2.0 times net earnings available for interest, which PSE exceeded at June 30, 2005;
- approximately $192 million of additional first mortgage bonds under PSE's gas mortgage indenture based on approximately $320 million of gas bondable property available for issuance, subject to an interest coverage ratio limitation of 1.75 times net earnings available for interest, which PSE exceeded at June 30, 2005;
- approximately $663 million of additional preferred stock at an assumed dividend rate of 6.375%; and
- approximately $193 million of unsecured long-term debt.

At June 30, 2005, PSE had approximately $3.6 billion in electric and gas ratebase to support the interest coverage ratio limitation test for net earnings available for interest.

CREDIT RATINGS

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

The ratings of Puget Energy and PSE, as of July 20, 2005, were as follows:

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

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

SHELF REGISTRATIONS, LONG-TERM DEBT AND COMMON STOCK ACTIVITY

On April 19, 2005, Puget Energy and PSE filed a shelf registration statement with the Securities and Exchange Commission for the offering, on a delayed or continuous basis, of up to $850 million of:

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

The shelf registration statement, effective as of May 4, 2005, replaces Puget Energy and PSE's previous $500 million shelf registration statement. The new shelf registration statement provides the Company with additional capacity and flexibility when funding anticipated capital projects and meeting maturing debt obligations.

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

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

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

LIQUIDITY FACILITIES AND COMMERCIAL PAPER

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

In May 2004, PSE entered into a three-year, $350 million unsecured credit agreement with a group of banks. In March 2005, PSE amended this credit agreement, increasing the total borrowing capacity from $350 million to $500 million, and extending the expiration date from June 2007 to April 2010. Under the terms of the credit agreement, PSE pays a floating interest rate on outstanding borrowings based either on the agent bank's prime rate or on LIBOR plus a marginal rate based on PSE's long-term credit rating at the time of borrowing. PSE pays a commitment fee on any unused portion of the credit agreement also based on long-term credit ratings of PSE. PSE also has available its $150 million receivables securitization program with Rainier Receivables, which expires in December 2005. At June 30, 2005, PSE had available $500 million in the unsecured credit agreement and $150 million under its receivables securitization facility, both of which provide credit support for outstanding commercial paper and letters of credit. At June 30, 2005, there was $159.6 million in commercial paper outstanding and $0.5 million outstanding under a letter of credit, effectively reducing the available borrowing capacity under these liquidity facilities to $489.9 million.

In February 2005, PSE entered into an uncommitted $20 million unsecured credit agreement with a bank. Under the terms of the credit agreement, PSE pays a varying interest rate on outstanding borrowings based on the terms entered into at the time of borrowing. At June 30, 2005, there were no amounts outstanding under this credit agreement.

Puget Energy has a $5 million credit agreement expiring in May 2006 with a bank. Under the terms of the agreement, Puget Energy pays a floating interest rate on borrowings based on LIBOR. The interest rate is set for one, two, or three-month periods at the option of Puget Energy with interest due at the end of each period. Puget Energy also pays a commitment fee on any unused portion of the credit facility. Puget Energy had $5 million outstanding under the credit agreement at June 30, 2005.

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 $3.7 million (168,213 shares) and $7.3 million (320,020 shares) for the three and six months ended June 30, 2005, respectively, compared to $3.8 million (178,551 shares) and $7.7 million (354,176 shares) for the three and six months ended June 30, 2004, respectively.

COMMON STOCK OFFERING PROGRAMS

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

Other

FERC HYDROELECTRIC PROJECTS AND LICENSES

Snoqualmie Falls project. The Snoqualmie Falls project, built in 1898, had its original license issued May 13, 1975, which was made effective retroactive to March 1, 1956, and expired on December 31, 1993. PSE filed its application to relicense the project on November 25, 1991, and operated the project pursuant to annual licenses issued by FERC since the original license expired. On June 29, 2004, FERC granted PSE a new 40-year operating license for the Snoqualmie Falls project. PSE estimates that the investment required to implement the conditions of the new license agreement will cost approximately $44 million. These conditions include modified operating procedures and various project upgrades that include better protection of fish, development of riparian habitat to promote fish propagation, increased minimum flows in the Snoqualmie River during low-water periods and the development of recreational amenities near the down-river power house. On July 29, 2004, the Snoqualmie Tribe and certain other parties filed a request for rehearing of the new license and a request to stay the FERC license. On March 1, 2005, FERC issued an Order on Rehearing and Dismissing Stay Request. The order requires additional flows at Snoqualmie Falls during certain times of the year. PSE requested rehearing of the order on the grounds that the order interferes with the State Department of Ecology's authority to regulate water quality and that FERC arbitrarily and capriciously rebalanced the public interest without support of substantive evidence in the record. The Snoqualmie Tribe subsequently appealed FERC's decision to the United States Court of Appeals for the Ninth Circuit and PSE intervened in that proceeding. PSE's request for rehearing was denied on June 1, 2005 and on July 8, PSE asked for further review of this order by the Ninth Circuit. PSE will seek to consolidate the two petitions into one review proceeding.

Baker River project. The Baker River hydroelectric project's current license expires on April 30, 2006, and PSE submitted an application for a new license to FERC on April 30, 2004. PSE reached a comprehensive settlement agreement with 23 parties on all issues relating to the relicensing of the project that must be approved by FERC in order to become effective. The proposed settlement includes a set of proposed license articles and, if approved by FERC without material modification, would allow a new license for 45 years or more. The proposed settlement would require an investment of approximately $360 million (capital expenditures and operations and maintenance cost) in order to implement the conditions of the new license over the next 30 years. FERC has not yet ruled on the proposed settlement and its ultimate outcome remains uncertain. In connection with the relicensing of the Baker River project, PSE is subject to additional regulatory approvals yet to be attained from various agencies. As required by the Coastal Zone Management Act (CZMA), PSE included a certification of consistency with Washington's Coastal Zone Management Program (CZMP). The CZMP requires the submission of applications for any required shoreline exemptions, permits or variances under the Washington Shoreline Management Act (SMA) in order to provide the State of Washington Department of Ecology with the necessary data and information to make its CZMA Consistency Determination. In March 2005, PSE made appropriate filings pursuant to the local shoreline regulations adopted by Whatcom County, Skagit County and the Town of Concrete. PSE filed requests for exemption in Whatcom County and Skagit County and a shoreline substantial development permit with the Town of Concrete. In May 2005, Skagit County entered a decision denying PSE's shoreline exemption application. On May 20, 2005, PSE appealed Skagit County's decision and challenged the denial of the shoreline exemption application. Hearings before the Skagit County Hearing Examiner on the exemption application determination are scheduled to take place later in 2005 and its outcome remains uncertain. On May 15, 2005, PSE received notice that FERC would issue a Draft Environmental Impact Statement (DEIS) in lieu of an Environmental Assessment (EA) for the Baker River project. FERC anticipates issuing the DEIS in the third quarter 2005, as opposed to May 2005 for the EA. The contents of the DEIS and potential impacts on the proposed settlement for the new license are as yet unknown. Further actions at FERC could have an impact on the schedule for issuing a new license.

ELECTRIC REGULATION AND RATES

FERC matter. PSE's market-based rate tariff was accepted by FERC in an order dated January 29, 1999. Pursuant to this order, PSE is required to file an updated market power analysis every three years. On August 11, 2004, PSE filed an updated market power analysis with FERC as required by a FERC order dated May 13, 2004. The August 11, 2004 filing was supplemented by additional filings on September 24, 2004 and November 19, 2004. On December 20, 2004, FERC issued an order (December 20 order) finding that PSE had not provided sufficient information for FERC to determine if PSE had passed the generation market power screens with respect to wholesale sales within PSE's control area. The order instituted an investigation under Section 206 of the Federal Power Act (FPA) and established a prospective refund date of February 27, 2005. Both the proceeding and the refund effective date affected only wholesale sales at market-based rates by PSE inside its own control area. On February 1, 2005, PSE submitted to FERC additional information in accordance with the December 20 order. On April 13, 2005, FERC issued an order terminating the Section 206 investigation and accepting PSE's updated market power analysis.

Power Cost Only Rate Case. On June 7, 2005, PSE filed a power cost only rate case (PCORC) with the Washington Utilities and Transportation Commission (Washington Commission) to help recover the higher cost of power. The PCORC requested a 3.7% increase in electric rates, or $55.6 million annually. Included in the request is recovery of capital and anticipated operating costs for the newly acquired Hopkins Ridge wind project once it goes online, which is expected in late 2005. The PCORC process is an accelerated rate proceeding where only power costs are reviewed. The PCORC proceeding can take up to five months to be concluded.

Least Cost Plan. PSE filed its electric Least Cost Plan on May 2, 2005 with the Washington Commission. The plan supports a strategy of diverse electric power and demand resource acquisitions including resources fueled by natural gas and coal, renewable resources (e.g. wind and biomass), and the implementation of energy efficiency strategies. The Least Cost Plan will be followed by issuing an all-source request for proposal (RFP) in late 2005. A draft version of the all-source RFP was filed with the Washington Commission on July 29, 2005.

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

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

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

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

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

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

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

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

Based on past activity under the PCA mechanism and volatility of power costs, it is possible that PSE could experience higher expenses associated with excess power based on the sharing arrangement once the cumulative $40 million cap expires on June 30, 2006. As such, the risk dynamics change for PSE and its customers. PSE is required by the Washington Commission to make a PCORC filing or general tariff filing by February 28, 2006 to reset the PCA power cost baseline rates effective July 1, 2006.

Tenaska Disallowance. The Washington Commission issued an order on May 13, 2004 determining that PSE did not prudently manage gas costs for the Tenaska electric generating plant and ordered PSE to adjust its PCA deferral account to reflect a one-time disallowance of accumulated costs under the PCA mechanism for these excess costs. The order also established guidelines and a benchmark to determine PSE's recovery on the Tenaska regulatory asset starting with the PCA 3 period (July 1, 2004) through the expiration of the Tenaska contract in the year 2011. The benchmark is defined as the original cost of the Tenaska contract adjusted to reflect the 1.2% disallowance from a 1994 Prudence Order.

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

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

The Washington Commission confirmed that if the Tenaska gas costs are deemed prudent, PSE will recover the full amount of actual gas costs and the recovery of the Tenaska regulatory asset even if the benchmark is exceeded. Due to fluctuations in forward market prices of gas, the amount and timing of any potential disallowance related to Tenaska can change significantly day to day. The projected costs and projected benchmark costs for Tenaska as of June 30, 2005, based on current forward market gas prices are as follows:

(Dollars in Millions)	Remaining 2005	2006	2007	2008	2009	2010	2011
Projected Tenaska costs *	$ 107.2	$ 219.2	$ 222.9	$ 218.4	$ 212.2	$ 204.9	$ 204.4
Projected Tenaska benchmark costs	82.0	167.8	175.3	182.2	189.5	197.2	213.8
Over (under) benchmark costs	$ 25.2	$ 51.4	$ 47.6	$ 36.2	$ 22.7	$ 7.7	$ (9.4)
Projected 50% disallowance based on Washington Commission methodology	$ 4.7	$ 8.8	$ 7.7	$ 6.3	$ 4.7	$ 2.0	$ --

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

FERC Standard Market Design. On July 19, 2005, FERC announced that it had officially abandoned efforts commenced in 2002 to create a Standard Market Design, stating that voluntary progress in the market had overtaken the need for a mandatory national approach. The decision to abandon the Standard Market Design initiative has no impact on PSE beyond the potential implications that completion of such an initiative would have had on PSE.

OTHER

Muckleshoot Indian Tribe vs. PSE Arbitration. On June 30, 2005 PSE received an adverse ruling by an arbitration panel awarding approximately $2.2 million in costs and interest for operations and maintenance of a fish hatchery on the White River owned and operated by the Muckleshoot Indian Tribe. The arbitration arose out of a disputed interpretation of a 1986 settlement agreement that resolved litigation brought by the tribe in the 1980’s regarding the White River project. The arbitration related to when the Company’s obligations to pay for the hatchery’s O&M costs ceased. Of the $2.2 million awarded, $1.4 million was charged to operation and maintenance expense and $0.8 million to interest expense in the second quarter 2005.

Colstrip Taxes and Royalties. The Minerals Management Service of the United States Department of the Interior issued an order on March 30, 2005 that approved in part and rejected in part the appeal filed by Western Energy Company (WECO) on the coal transportation revenues. On June 17, 2005 WECO filed a further appeal of that order to the US Department of the Interior Board of Land Appeals. No decision in that process is expected for over a year.

Notice of Proposed Adjustment by the Internal Revenue Service. On July 12, 2005, Puget Energy received a notice of proposed adjustment (NOPA) from the Internal Revenue Service relating to a deduction in Puget Energy's 2003 tax return. The deduction relates to the receivable balance due from the California Independent System Operator Corporation. The NOPA states that the deduction is not valid for the 2003 tax year, and requests payment of approximately $14.5 million in taxes and approximately $1.0 million in related interest. Management of Puget Energy believes the deduction is valid and intends to vigorously defend the deduction, however the outcome of this issue cannot be predicted. Any potential tax related payment (excluding interest) would have no impact on earnings as it would be recognized as a deferred tax asset.

PROCEEDINGS RELATING TO THE WESTERN POWER MARKET

Puget Energy's and PSE's Annual Report on Form 10-K for the year ended December 31, 2004 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 include a summary and subsequent developments relating to the western power market proceedings described below. The following discussion provides a summary of material developments in these proceedings that occurred during the period covered by this report and of any new material proceedings instituted during the period covered by this report. PSE intends to vigorously defend against each of these cases and does not expect the ultimate resolution of these proceedings in the aggregate to have a material adverse impact on the financial condition, results of operations or liquidity of the Company. However, there can be no assurances in that regard because litigation is subject to numerous uncertainties and PSE is unable to predict the ultimate outcome of these matters. Accordingly, there can be no guarantee that these proceedings, either individually or in the aggregate, will not materially and adversely affect PSE's financial condition, results of operations or liquidity.

1. **California Refund Proceeding.** On July 25, 2001, FERC ordered an evidentiary hearing (Docket No. EL00-95) to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CAISO and the California PX during the period October 2, 2000 through June 20, 2001 (refund period). The CAISO continues its efforts to prepare revised settlement statements based on newly recalculated costs and charges for spot market sales to California during the refund period and currently estimates that it will preliminarily determine "who owes what to whom" sometime in 2005 or 2006. A review of that claim is pending, especially in light of a June 27, 2005 FERC order clarifying the methodology for submitting fuel cost claims. Within the last several months, global settlements have been announced and/or approved, including settlements between the California Parties and Williams, Duke, El Paso, Mirant, Dynegy, and Enron. These settlements, supported by a recent statement from the new FERC chairman Joseph Kelliher may suggest that the process momentum toward settlement in the California Refund Proceedings is increasing.

2. **Pacific Northwest Refund Proceeding.** On June 25, 2003, FERC issued an order terminating the proceeding, largely on procedural, jurisdictional and equitable grounds. Various parties filed rehearing requests, which were denied by FERC in an order affirming the termination of the Pacific Northwest Refund Proceeding, (Docket No. EL01-10). Seven petitions for review, including PSE's, are now pending before the United States Court of Appeals for the Ninth Circuit. Briefing is complete and the Ninth Circuit is expected to schedule oral argument during the fall of 2005. An order that assigned the case to the same panel that decided the Lockyer case, which is described in the Company's Annual Report on Form 10-K for the year ended December 31, 2004, was issued on July 13, 2005.

3. **Wah Chang v. Avista Corp., PSE and others.** In June 2004, Puget Energy and PSE were served a federal summons and complaint by Wah Chang, an Oregon company. Wah Chang claims that during 1998 through 2001 the Company and other energy companies (and in a separate complaint, energy marketers) engaged in various fraudulent and illegal activities including the transmittal of electronic wire communications to transmit false or misleading information to manipulate the California energy market. The claims include submitting false information such as energy schedules and bids to the California PX, CAISO, electronic trading platforms and publishers of energy indexes, alleges damages of not less than $30 million and seeks treble and punitive damages, attorneys' fees and costs. The complaint is similar to the allegations made by the Port of Seattle currently on appeal in the Ninth Circuit. Both cases were dismissed on the grounds that FERC has the exclusive jurisdiction over plaintiff's claims and the filed rate doctrine and Federal preemption barred the court from hearing the plaintiff's claims. On March 10, 2005, Wah Chang filed a notice of appeal to the United States Court of Appeals for the Ninth Circuit. On May 17, 2005, Wah Chang filed a motion to stay or, in the alternative, dismiss its appeal without

prejudice to reinstatement. The defendants responded on May 25, 2005, opposing the motion and filed a cross-motion for summary affirmance of the judgment. The motions were denied on July 8, 2005 although defendants may renew the motion for summary affirmance after Wah Chang files its opening brief, which is due sometime in the third quarter 2005.

4. **California Litigation.** *California Class Actions.* In May 2002, PSE was served with two cross-complaints, by Reliant Energy Services and Duke Energy Trading & Marketing, respectively, in six consolidated class actions filed in Superior Court in San Diego, California. Plaintiffs in the lawsuits seek, among other things, restitution of all funds acquired by means that violate the law and payment of treble damages, interest and penalties. The cross-complaints asserted essentially that the cross-defendants, including PSE, were also participants in the California energy market at relevant times, and that any remedies ordered against some market participants should be ordered against all. Reliant and Duke also seek indemnification and conditional relief as buyers in transactions involving cross-defendants should the plaintiffs prevail. The case was removed to federal court and in December 2002, the federal district court remanded the proceeding to state court, an action which Duke and Reliant later appealed to the Ninth Circuit. The Ninth Circuit remanded the case to state court. On June 3, 2005, the cross-defendants, including PSE, filed a demurrer seeking to dismiss the action. Further briefing and hearing on the demurrer is currently stayed pending the outcome of demurrers filed by Duke and Reliant on the main complaint, which currently is set to be heard on September 9, 2005. In addition, on July 22, 2005 the court considered a proposed settlement that would resolve all claims against the Duke parties and indicated "preliminary approval," setting a hearing date for final approval of December 9, 2005.

Item 3. **<u>Quantitative and Qualitative Disclosure About Market Risk</u>**

ENERGY PORTFOLIO MANAGEMENT

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

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

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

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

The Company is not engaged in the business of assuming risk for the purpose of speculative trading revenues. Therefore wholesale market transactions are focused on balancing the Company's energy portfolio, reducing costs and risks where feasible, and reducing volatility in wholesale costs and margin in the portfolio. In order to manage risks effectively, the Company enters into physical and financial transactions, which are appropriate for the service territory of the Company and are relevant to its regulated electric and gas portfolios. The risk metrics the Company employs are aimed at assessing exposure in the regulated energy portfolios, and for purposes of developing strategies to reduce the potential exposure. Specifically, the amount of risk exposure is defined by time period and by portfolio. It is determined through statistical methods aimed at forecasting risk.

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

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

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

The Company has entered into master netting agreements with counterparties when available to mitigate credit exposure to those counterparties. The Company believes that entering into such agreements reduces risk of settlement default with the ability to make only one net payment. In addition, the Company believes risk is mitigated with an improved position in potential counterparty bankruptcy situations due to a consistent netting approach. At June 30, 2005, the Company is subject to a range of netting provisions, including both stand alone agreements and the provisions associated with the Western Systems Power Pool agreement of which many energy suppliers in the western United States are a part.

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

At June 30, 2005, the Company had a net asset of approximately $49.2 million of energy contracts designated as qualifying cash flow hedges and a corresponding unrealized gain of $31.9 million after-tax recorded in other comprehensive income. Of the amount in other comprehensive income, 99% of the mark-to-market gain beginning September 1, 2005 though June 30, 2006 has been reclassified out of other comprehensive income to a deferred account in accordance with SFAS No. 71 due to the Company reaching the $40 million cap under the PCA mechanism. Amounts settling after June 30, 2006 have not been deferred under the PCA mechanism as the $40 million cap expires at June 30, 2006, and the sharing band under the PCA mechanism reset. The Company also had energy contracts that were marked-to-market at a gain of $0.6 million through current earnings for the three months ended June 30, 2005 and at a gain of $0.1 million for the six months ended June 30, 2005. These mark-to-market adjustments were primarily the result of excluding certain contracts from the normal purchase normal sale exception under SFAS No. 133. A portion of the mark-to-market adjustments beginning September 1, 2005, has been reclassified to a deferred account in accordance with SFAS No. 71 due to the

Company reaching the $40 million cap under the PCA mechanism. At June 30, 2005, the Company also has an asset of approximately $14.2 million related to the fair value of gas contracts to serve 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. The PGA mechanism passes on to customers increases and decreases in the cost of natural gas supply. A hypothetical 10% increase in the market prices of natural gas and electricity would increase the fair value of qualifying cash flow hedges and comprehensive income by approximately $9.9 million after-tax and would increase current earnings for those contracts marked-to-market in earnings by $1.7 million pre-tax. All items affecting comprehensive income are presented after-tax as items recorded in comprehensive income are net of tax.

INTEREST RATE RISK

The Company believes its interest rate risk primarily relates to the use of short-term debt instruments, variable-rate notes and leases and long-term debt financing needed to fund capital requirements. The Company manages its interest rate risk through the issuance of mostly fixed-rate debt of various maturities. The Company utilizes bank borrowings, commercial paper, line of credit facilities and accounts receivable securitization to meet short-term cash requirements. These short-term obligations are commonly refinanced with fixed-rate bonds or notes when needed and when interest rates are considered favorable. The Company may at times enter into variable rate long-term bonds to take advantage of lower interest rates. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts.

In the second quarter 2005, the Company entered into two forward starting swap contracts to hedge against interest rate volatility for a debt offering anticipated to be performed in the second half of 2006. A forward starting swap is a financial arrangement between the Company and a counterparty whereby one of the parties will be required to make a payment to the other party on a specific valuation date based upon the change in value of a designated treasury bond. If interest rates rise related to the hedged debt from the date of issuance of the swap instruments, the Company would receive a payment from the counterparty for the change in the bond value. Alternatively, if interest rates decreased related to the hedged debt from the date of issuance of the swap instruments, the Company would pay the counterparty for the change in bond value. These swap contracts were designated under SFAS No. 133 criteria as cash flow hedges, with all changes in market value for each reporting period being presented net of tax in other comprehensive income. All financial hedge contracts of this type are reviewed by senior management and presented to the Securities Pricing Committee of the Board of Directors, and are approved prior to execution. At June 30, 2005, the unrealized loss associated with the two swap contracts was $7.6 million after-tax and is included in other comprehensive income. A hypothetical 10% decrease in the interest rate of a 30-year treasury note would result in an additional loss of $9.4 million after-tax in other comprehensive income. The swap contracts will settle completely in 2006.

Item 4. **Controls and Procedures**

PUGET ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of Puget Energy’s management, including the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, Puget Energy has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of June 30, 2005, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer of Puget Energy concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in Puget Energy’s internal control over financial reporting during the quarter ended June 30, 2005 that have materially affected, or are reasonably likely to materially affect, Puget Energy’s internal control over financial reporting.

PUGET SOUND ENERGY

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Under the supervision and with the participation of PSE's management, including the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer, PSE has evaluated the effectiveness of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of June 30, 2005, the end of the period covered by this report. Based upon that evaluation, the President and Chief Executive Officer and Senior Vice President Finance and Chief Financial Officer of PSE concluded that these disclosure controls and procedures are effective.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in PSE's internal control over financial reporting during the quarter ended June 30, 2005, that have materially affected, or are reasonably likely to materially affect, PSE's internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. **Legal Proceedings**

See the section titled "Proceedings Relating to the Western Power Market" under Item 2 "Management's Discussion and Analysis of Financial Conditions and Results of Operations" of this Quarterly Report on Form 10-Q.

Contingencies arising out of the normal course of the Company's business exist at June 30, 2005. The ultimate resolution of these issues in part or in the aggregate is not expected to have a material adverse impact on the financial condition, results of operations or liquidity of the Company.

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

Puget Energy's annual meeting of shareholders was held on May 10, 2005. At the annual meeting, the shareholders elected three directors to hold office until the annual meeting of shareholders in 2008 or until their successors are elected and qualified. In addition, the shareholders elected one director to hold office until 2006. The vote was as follows:

	Number of Shares	
	For	Withheld
TERM EXPIRING 2008		
William S. Ayer	83,172,755	1,669,494
Robert L. Dryden	78,082,461	1,917,850
Sally G. Narodick	82,731,077	2,111,172
TERM EXPIRING 2006		
Charles W. Bingham	82,924,399	1,917,850

There were no abstentions and no broker non-votes.

The terms of the following directors continued after the annual meeting:

Craig W. Cole
Tomio Moriguchi
Phyllis J. Campbell
Stephen E. Frank
Dr. Kenneth P. Mortimer
Stephen P. Reynolds

Douglas P. Beighle, Chairman of the Boards of Directors of Puget Energy and Puget Sound Energy since March 2002, retired from the Board on May 10, 2005 after the Annual Meeting of Shareholders. On May 10, 2005, the Board appointed Stephen P. Reynolds to serve as Chair of the Boards of Puget Energy and Puget Sound Energy, and appointed Phyllis J. Campbell to serve as Lead Director.

In addition to the election of the Directors at the Annual Meeting of Shareholders, the shareholders of Puget Energy approved the Puget Energy, Inc. Amended and Restated Nonemployee Director Plan (NED Plan) and the Puget Energy, Inc. 2005 Long-Term Incentive Plan (2005 LTIP), which amended in its entirety and restated the Puget Energy, Inc. 1995 Long-Term Incentive Compensation Plan as previously approved by shareholders (1995 LTIP). Shareholders also ratified PricewaterhouseCoopers LLP as the Company's independent registered accounting firm.

The Board of Directors originally adopted the NED Plan on October 7, 1997, at a time when shareholder approval of the plan was not required. As amended and restated, the NED Plan includes the following material revisions from the plan as originally adopted by the Board:

- an increase of 250,000 shares in the number of shares authorized for issuance, from 100,000 to 350,000; and
- an extension of the term of the plan from December 31, 2007 to December 31, 2015.

The 2005 LTIP includes the following material revisions from the 1995 LTIP:

- an increase of 3,000,000 shares in the number of shares authorized for issuance, from 1,200,000 to 4,200,000;
- the addition of share replenishment features;
- the expansion of the persons eligible to participate in the plan to include all employees, other service providers and nonemployee directors;
- the expansion of the types of awards available for grant to also include cash-based awards that can qualify as performance-based for purposes of Section 162(m) of the Internal Revenue Code of 1986 (Section 162(m));
- the expansion of the list of performance criteria for purposes of performance-based awards under Section 162(m);
- an increase in the number of shares subject to awards intended to qualify as performance-based under Section 162(m) that may be granted to any individual during any calendar year, from 40,000 shares to (a) 600,000 shares, with respect to stock options and stock appreciation rights and (b) 400,000 shares, with respect to awards other than stock options, stock appreciation rights or performance units;
- an increase in the maximum dollar value payable with respect to performance units intended to qualify as performance-based under Section 162(m) to any individual during any calendar year, from $400,000 to $3,000,000; and
- the addition of a ten-year term to the plan, which previously had no expiration date.

The vote for these matters was as follows:

	Number of Shares		
	For	Against	Abstain
Long-term Incentive Plan	56,425,063	8,355,168	1,454,614
Nonemployee Director Stock Plan	57,139,518	7,516,861	1,578,466
Ratify PricewaterhouseCoopers LLP	82,678,961	1,414,353	748,935

The Long-term Incentive Plan and Nonemployee Director Stock Plan both received 18,607,404 broker non-votes.

Item 6. **Exhibits**

See Exhibit Index for list of exhibits.

SIGNATURES

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

PUGET ENERGY, INC.
PUGET SOUND ENERGY, INC.

/s/ James W. Eldredge
James W. Eldredge
Vice President, Corporate Secretary
and Chief Accounting Officer

Date: August 2, 2005

Chief accounting officer and officer duly authorized to
sign this report on behalf of each registrant

EXHIBIT INDEX

The following exhibits are filed herewith:

12.1 Statement setting forth computation of ratios of earnings to fixed charges (2000 through 2004 and 12 months ended June 30, 2005) for Puget Energy.

12.2 Statement setting forth computation of ratios of earnings to fixed charges (2000 through 2004 and 12 months ended June 30, 2005) for PSE.

31.1 Chief Executive Officer certification of Puget Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Chief Financial Officer certification of Puget Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.3 Chief Executive Officer certification of Puget Sound Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.4 Chief Financial Officer certification of Puget Sound Energy pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Chief Executive Officer certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Chief Financial Officer certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.